ALTERNATIVE OPTIONS
FOR SUPPLYING ELECTRICAL POWER
TO BAMFIELD AND BELLA BELLA, B.C.

ALTERNATIVE OPTIONS FOR SUPPLYING ELECTRICAL POWER TO BAMFIELD AND BELLA BELLA, B.C.

For and By:

B.C. Hydro

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FOREWORD

B.C. Hydro prepared this report on "Alternative Energy Options for Supplying Electrical Power to Bamfield and Bella Bella, British Columbia" with assistance from the Government of Canada. Energy, Mines and Resources Canada supplied 50 percent of the funding under the Remote Community Demonstration Program.

B.C. Hydro presently supplies electrical power to the communities of Bamfield and Bella Bella, as well as other nearby communities, from diesel generating stations at Bamfield and Shearwater. The cost of diesel fuel has escalated rapidly in recent years. This has increased the cost of energy produced by these generating stations to the point where other alternative fuels and other means of power generation may now be feasible. In the past these alternatives were considered to be unsuitable and/or uneconomic for remote communities.

The purpose of this preliminary evaluation is to review the present means of supplying electrical energy to the B.C. Hydro systems at Bamfield and Bella Bella and to consider the potential and cost of supplying the existing and future requirements from alternative sources of energy.

In this report approximate costs are estimated for the specified generating units installed at specific locations. These units were selected for illustration only and they are not necessarily the best or most economical units. Similarly, the sites selected are also for illustration only and do not imply that those locations are the most suitable. Further studies on any alternative would require a more detailed investigation of both suppliers of generating units and sites for a plant.

SUMMARY

The status of the existing diesel electric generating stations at Bamfield and Shearwater is examined in this report and the costs of energy from these stations are compared with the alternative energy sources which could be developed in these areas. The report is divided into four parts. The first part includes the Summary, Recommendations and Terms of Reference. The second part (Part A) describes alternative energy options as they apply to Bamfield. The third part (Part B) describes alternative energy options as they apply to Bella Bella. The fourth part (Appendices) describes the status of alternative energy technologies, background information on the cost estimates and a glossary of technical terms and abbreviations to assist the reader.

PART A - BAMFIELD

In 1982/83 the peak load and annual energy for the Bamfield diesel generating station were 0.65 MW and 3.14 GW·h respectively. For this report it was assumed that the peak load would continue to grow at 5.3 percent per annum and the energy demand would grow at 5.0 percent per annum. As a result, the projected peak load in 1990/91 would be 0.98 MW and the corresponding annual energy would be 4.65 GW·h. It was also assumed that these growth rates would continue unchanged thereafter.

All cost estimates are stated in terms of March 1984 dollars. Gross unit energy costs are based on the projected 1990/91 load. In estimating payback periods, it is assumed that the cost of diesel fuel will increase at the rate of inflation until 1986/87 and rise at 1 percent net of inflation thereafter.

The estimated costs of energy from the alternative energy sources near Bamfield are compared in the following table and they are examined in detail in Part A, Section 7.0 of this report. The results of this preliminary evaluation of the alternative energy sources potentially available to Bamfield are as follows:

1. Energy sources which could provide economical alternatives to diesel power generation at Bamfield (based on gross unit energy cost):

    a. Small Hydroelectric Generation at Sarita River - The unit energy cost from a 1.0 MW hydroelectric generating station on the Sarita River, 19 km from Bamfield, is estimated to be 104 mills/kW·h. Small hydroelectric generation could provide an estimated 4.65 GW·h of energy in 1990/91 and as much as 6.1 GW·h/a when demand is higher in the future. The size of the plant would be limited by low summer flows on the Sarita River.

Small hydroelectric power generation alone could not supply all of the electrical energy required in the future and supplementary diesel generation would be required in order to serve the increasing demand and particularly the peak load. The addition of the supplementary diesel generation would increase the unit energy cost in 1990/91 to 127 mills/kW·h. The payback period for the small hydroelectric/diesel combination is estimated to be more than 20 years based on a 1990/91 in-service date.

The environmental impacts of a small hydroelectric development would not be significant because the level of Sarita Lake would not be raised and the generating station would be located at the upper limit of salmon migration.

b. Distribution Line From Port Alberni (China Creek) - A 25 kV, 3-phase distribution line has been proposed from China Creek to Bamfield. The line would be 73 km long, generally follow the existing logging roads and could be completed by 1986/87. It is estimated that this line could provide an economical alternative to diesel power generation at 118 mills/kW·h in 1990/91. This is more than the estimated cost of small hydroelectric generation, but distribution could provide for substantial growth at decreasing unit energy cost in the future, whereas the small hydroelectric alternative has limited growth potential.

The payback period for a distribution line from China Creek is estimated to be 12 years, which is appreciably less than the payback period for small hydroelectric generation.

A distribution line could be constructed along the existing access road from Port Alberni to Bamfield with little environmental impact. There would be some loss of forestry values because of land alienation along the right-of-way.

2. Energy sources which would be less economical than diesel power generation at Bamfield (based on gross unit energy cost):

a. Tidal Power Generation at Bamfield Inlet - The potential for a 500 kW tidal generating station on Bamfield Inlet was examined briefly as a potential source of electrical energy for Bamfield. The proposed tidal generating station could only supply 1.4 GW·h/a because of the low capacity factor and low tidal range. The gross unit energy cost is estimated to be 416 mills/kW·h, which is substantially more than the cost of diesel generation. In addition, tidal power is intermittent, but predictable, so it could only be considered as a fuel saver. Diesel generation or another dependable source of electrical power would be required for back-up.

COMPARATIVE ENERGY COSTS*1 - BAMFIELD

	Diesel Bamfield	Small Hydroelectric Sarita River	Tidal Bamfield Inlet	Wind Pachena	Thermal Roquefeuil Bay			Distribution Port Alberni - Bamfield
					Wood	Wood-Gas	Coal	
Plant Capacity (MW)	1.7	1.0	0.5	0.30	1.0	1.0	1.0	1.8
Annual Energy (GW·h)	4.65	4.65	1.40	0.16	4.65	4.65	4.65	4.65
Project Cost ($/kW)*2	710	5903	14 374	4643	6476	5116	5793	1993
Total Capital Cost (k$)*3	1207	6505	7927	1518	7255	5686	6411	3911
Equivalent Fuel Cost (mills/kW·h)	117	-	-	-	68	89	29	-
Gross Unit Energy Cost (mills/kW·h)	161	104	416	872	253	232	193	118
Payback Period (a)	-	>20	-	-	-	-	>20	12

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*1 1984 dollars at a 4 percent net discount rate.

*2 Includes construction, engineering and contingency costs.

*3 Includes construction, engineering, overhead and I.D.C. costs.

The environmental impacts of tidal generation on Bamfield Inlet could be considerable. Access to a proposed marina and to a few residences up the inlet from the barrage would be blocked by a tidal development.

b. Wind Power Generation near Pachena Bay - In 1981 the National Research Council and B.C. Hydro constructed a wind monitoring station on a hill overlooking Pachena Bay. In this study that site was selected for a 300 kW wind farm using six 50 kW vertical axis wind turbines. It is estimated that a wind farm of this size could only produce 160 MW·h/a of electrical energy because of the adverse wind regime. On this basis the gross unit energy cost is estimated to be 872 mills/kW·h. Wind is intermittent; therefore, wind generators could only be used as diesel fuel savers. Diesel generation would be required most of the time which would further increase costs.

The principal environmental impact of wind generation would be the land alienation. The land required for this wind farm would be approximately 9 ha and this land would be unavailable for forestry development which is the present land use.

c. Wood-Fired Thermal Power Generation at Roquefeuil Bay - A wood-fired thermal plant could be supplied with wood waste from landings and along logging roads. The present estimate for the cost of wood-fired thermal power generation is 253 mills/kW·h. The equivalent energy cost of the fuel component is estimated to be 68 mills/kW·h. The fuel cost would increase disproportionately with increasing energy demand because additional fuel would be brought from farther away, but this effect would be partly offset by savings at the powerplant.

The environmental impacts from a wood-fired thermal plant using wood waste would be small because the plant would be small. Some benefit would be derived from more efficient use of the forestry resource.

d. Wood Gasification-Engine Generating Plant at Roquefeuil Bay - The sources of wood waste would be the same as in the case of a wood-fired thermal plant, but wood gasification would require approximately 24 percent more fuel because of the lower overall efficiency of the process. The gross unit energy cost is estimated to be 232 mills/kW·h. A small amount of diesel generation and diesel fuel would be required to supplement the gas-fired generation and the gas derived from wood waste.

The environmental impacts would be similar to those for wood-fired thermal power generation.

e. Coal-Fired Thermal Power Generation at Roquefeuil Bay - The cost of energy from a 1 MW coal-fired thermal plant at Roquefeuil Bay, 6 km from Bamfield, is estimated to be 193 mills/kW·h. It is assumed that coal would be brought by tug and barge from Vancouver (possibly Roberts Bank) at a delivered cost of $61.25/t. Coal-fired thermal power generation could supply any amount of electrical power by increasing the plant capacity as required to meet the load. The availability of fuel would not be a limiting factor.

It has been assumed that diesel generating units would meet 10 percent of the load by providing energy for black starts and peaking. New diesel units would be added as required. New coal-fired units would be added when the capacity factor of the earlier units would reach 75 percent.

The environmental impacts of a coal-fired thermal plant are not expected to be significant because the plant would be designed to meet all government emission standards and because the plant would be small and the total emissions would be correspondingly low. Once-through cooling would be used; the water would be taken from Roquefeuil Bay.

f. Other Resources - Alternative gaseous or liquid fuels would not be suitable for the existing power station because of problems in transportation, storage and/or utilization in the present diesel generating units. There are no known geothermal or peat resources near Bamfield; therefore, these technologies would not be suitable. Wave power and solar power technologies are not sufficiently developed for consideration at Bamfield.

PART B - BELLA BELLA

The peak load (1982/83) and the annual energy for the Shearwater (Bella Bella) diesel generating station was 1.80 MW and 7.74 GW·h respectively. For this report it was assumed that the peak load would continue to grow at 4.5 percent per annum and the energy demand would grow at 3.7 percent per annum. As a result, the projected peak load in 1990/91 would be 2.55 MW and the corresponding annual energy would be 10.35 GW·h. It was also assumed that these growth rates would continue thereafter.

The gross unit energy costs are in March 1984 dollars and assume a 1990/91 load. The estimated costs of energy from the alternative resources near Bella Bella are compared in the following table and they

COMPARATIVE ENERGY COSTS*1 - BELLA BELLA

	Diesel	Small Hydroelectric		Tidal	Wind	Thermal			Transmission
						Wood	Wood-Gas	Coal	
	Shearwater	Walker Lake	Lakes A, B, C and D	Hochstader Basin	Mount Hand	Norman	Morrison	Bay	Ocean Falls Shearwater
Plant Capacity (MW)	3.6	1.1	0.5	2.0	0.80	2.0	2.62	2.0	14.0
Annual Energy (GW·h)	10.35	7.70	3.50	7.00	2.26	10.35	10.35	10.35	10.35
Project Cost ($/kW)*2	516	9159	9640	7218	5885	5123	4157	4704	528
Total Capital Cost ($k)*3	1859	11 171	5313	15 915	5132	11 483	12 112	10 415	8141
Fuel Cost (mills/kW·h)	102	-	-	-	-	79	93	29	-
Gross Unit Energy Cost (mills/kW·h)	158	109	111	169	209	211	240	150	100
Payback Period (a)	-	>20	-	>20	-	-	-	>20	10

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*1 At 4 percent net discount rate.

*2 Includes construction, engineering and contingency costs.

*3 Includes construction, engineering, overhead and I.D.C. costs.

are examined in detail in Part B, Section 7.0 of this report. The results of this preliminary evaluation of the alternative energy sources potentially available to Bella Bella are as follows:

1. Energy sources which could provide economical alternatives to diesel power generation at Bella Bella (based on gross unit energy cost):

    a. Small Hydroelectric Generation at Walker Lake - A 1.1 MW small hydroelectric generating station on Johnson Channel at the mouth of the creek draining from Walker Lake could provide an estimated 7.7 GW·h/a in 1990/91. This generation assumes some storage in Walker Lake. An overland distribution line 27 km long and 1.5 km of submarine cable would be required between the proposed powerhouse and Shearwater.

        The gross unit energy cost is estimated to be 109 mills/kW·h for a small hydroelectric plant at Walker Lake. The cost would rise to 131 mills/kW·h (1990/91) if the cost of supplementary diesel generation is added. The payback period is estimated to be more than 20 years because of the appreciable supplementary generation (assumed to be diesel) required in the future.

        The environmental impacts resulting from a small hydroelectric development on the creek draining from Walker Lake are expected to be small. Salmon spawn only in the lower 400 m of the creek because they are blocked at that point by a 12 m waterfall.

    b. Small Hydroelectric Generation at Lakes A, B, C and D - A second small hydroelectric site associated with four lakes designated A, B, C and D was identified in a 1963 B.C. Hydro report. The site is on Denny Island, 13 km from Shearwater and could provide sufficient flow for a 0.5 MW plant. It is estimated that 3.5 GW·h/a could be produced from this proposed small hydroelectric plant. The estimate assumes that a small dam could be constructed on the upper part of the Kajusdus Creek in order to divert flow from Lake D into the creek draining from Lake C. If this diversion is not feasible it is estimated that the available energy would be reduced by 15 percent.

        The gross unit energy cost from a small hydroelectric project on Lakes A, B, C and D is estimated to be 111 mills/kW·h. The payback period was not calculated because it would be slightly less economical than Walker Lake and the site was not visited on the trip to Bella Bella; therefore, little is known about the site.

There are significant salmon spawning runs on the Kajusdus Creek which drains from Lake D, but the impact on fisheries resulting from damming a small tributary near the headwaters is unknown. A lesser impact would be the visual effect of the 14 km distribution line to Shearwater.

c. Tidal Power Generation at Hochstader Basin - It is estimated that a 2 MW tidal generating station near the entrance to Hochstader Basin could supply 7 GW·h/a based on a 40 percent annual capacity factor. The gross unit energy cost in 1990/91 is estimated to be 169 mills/kW·h, which is somewhat more than the total cost of diesel generation and considerably more than the cost of diesel fuel. It would be necessary to have a back-up form of reliable generation because tidal power is intermittent and could only be considered as a diesel fuel saver. The addition of supplementary diesel generation increases the estimated cost of energy from tides to 176 mills/kW·h, which is considerably more than the cost of diesel generation.

The environmental impacts of tidal development on Hochstader Basin are expected to be minor. Although there was salmon and herring fishing associated with the basin in the past, these fisheries are believed to be small and they are not presently exploited by local fishermen.

d. Coal-Fired Thermal Power Generation at Norman Morrison Bay - It is assumed that coal could be supplied in essentially unlimited quantities from Ridley Island near Prince Rupert. The delivered cost of coal is estimated to be $61.45/t today and the cost of coal F.O.B. Ridley Island is assumed to rise at 0.5 percent (net of inflation) from 1990/91 onward. The gross unit energy cost from coal-fired thermal power generation at Norman Morrison Bay is estimated to be 150 mills/kW·h in 1990/91.

An allowance has been made for supplementary diesel power generation to provide for peaking and black start capability. This allowance would increase the cost of energy to 161 mills/kW·h. It is assumed that new coal-fired units would be added when the capacity factor of the old units would reach 75 percent and additional diesel generation would be added for peaking. The payback period for coal-fired generation is estimated to be more than 20 years.

The environmental impacts for a coal-fired generating station would be small. Air emissions and solid waste from the plant would be controlled by permits issued under the Waste Management Act.

e. Transmission from Ocean Falls to Shearwater - There is an existing hydroelectric generating station at Ocean Falls. This station was used to provide power for the pulp mill which is closed and the community which is largely abandoned. A 69 kV, 3-phase, wood pole transmission line could be constructed from Ocean Falls to Shearwater. Several potential routes were examined in a study conducted by Reid Crowther and Partners Limited. One of these routes, which includes 52 km of overhead transmission and 1.5 km of submarine transmission, was selected for this report.

This report examines only the cost of energy at Bella Bella and does not imply ownership of any of the facilities from the Shearwater terminus toward Ocean Falls. The gross unit energy cost is estimated to be 100 mills/kW·h (1990/91), which makes it the most economical of any of the alternatives examined for Bella Bella. It is assumed that no diesel back-up would be required, although some diesel generation may be required for security in the early years of operation and perhaps into the future as well. The payback period is estimated to be 10 years.

The environmental impacts of a transmission line from Ocean Falls to Bella Bella arise principally from construction and land alienation. Line crossings may cause some turbidity in creeks during the construction phase. Considerable land would be alienated by the line and forestry values would be affected. In addition, the visual impact of a linear cut through the trees could be significant.

2. Energy sources which would be less economical than diesel power generation at Bella Bella (based on gross unit energy cost):

a. Wind Power Generation at Mount Hand - To date there has been no wind monitoring of high sites near Bella Bella. The existing sites are near sea level and records indicate that the best sites are those accessible to winds off the open ocean. A site on Mount Hand was selected as a potential site for a wind farm consisting of four 200 kW horizontal axis wind turbines. The annual energy is estimated to be only 2.26 GW·h resulting in a gross unit energy cost which is estimated to be 209 mills/kW·h. Because wind generation could only be regarded as a diesel fuel saver, supplementary diesel generation would be required which would further increase the overall cost of wind generation.

The environmental implications of wind generation result mainly from land alienation and visual impacts.

b. Wood-Fired Thermal Power Generation at Norman Morrison Bay - A wood-fired thermal plant at Norman Morrison Bay on Campbell Island would have to be based on tree farming because of a general lack of wood waste in the area. The cost of wood from tree farms is estimated to be $80.55/ODtonne which is considerably more than the delivered cost of coal (both by weight and by energy content). The estimated gross unit energy cost for a wood-fired thermal plant at Norman Morrison Bay is 211 mills/kW·h.

It is unlikely that there is sufficient, suitable land available on Campbell Island to support a tree farm which could supply the future needs of the generating station. Therefore, supplementary generation would be required to provide for future demands as well as black start capability. It is assumed that wood-fired generation could pick up the expanded demand until the year 2006. At that time new generation would be diesel-powered or from another alternative. On this basis and assuming supplementary diesel generation, the gross unit energy cost in 1990/91 is estimated to be 224 mills/kW·h.

The principal environmental impact would be land alienation resulting from tree farming operations. Approximately 3600 ha of dedicated land would be required for a sustained yield to supply a 3 MW plant. An additional environmental impact would be the increased turbidity in lakes and creeks which could result from tree farming operations.

c. Wood Gasification-Engine Generating Plant at Norman Morrison Bay - A wood gasification-engine generating plant at Norman Morrison Bay could supply approximately 2.6 MW of electrical power. The plant size is limited by the space available for tree farming. The gross unit energy cost is estimated to be 240 mills/kW·h, which is the least economical of the alternatives examined for Bella Bella. The cost of supplementary diesel generation for serving the load in 1990/91 and the cost of additional diesel generation to serve future loads tends to make wood gasification an even more expensive alternative.

The environmental impacts from wood gasification-engine generation would be similar to those for wood-fired thermal generation.

d. Other Resources - The problems with utilizing alternative fuels in the existing diesel plant, geothermal power, peat-fired thermal power, wave power and solar power are similar to using these technologies at Bamfield. Comments provided in the discussion of these alternatives would apply to Bella Bella as well.

RECOMMENDATIONS

The following recommendations are made on the basis of this preliminary evaluation:

1. B.C. Hydro could continue to supply electrical power to Bamfield and the surrounding communities by using diesel generation, but the cost would continue to be high. It is recommended that B.C. Hydro proceed with the plan to integrate Bamfield into the grid by constructing a 25 kV, 3-phase distribution line from Port Alberni. This alternative would certainly be economical before the base year 1990/91 which was selected for this report. Small hydroelectric development would provide an alternative for local generation, but it is less economical than integration and should only be examined further if the distribution line should become overloaded at some time in the future.

2. Similarly, B.C. Hydro could continue to supply electrical power to Bella Bella and the surrounding communities by using diesel generation, but the cost would continue to be high. It is recommended that B.C. Hydro continue to examine the feasibility of supplying electrical power to Bella Bella by means of a 69 kV, 3-phase transmission line from Ocean Falls. This alternative would be the most economical in the base year 1990/91. If this alternative should prove infeasible, the methods of local generation which should be investigated are coal-fired thermal and small hydroelectric power generation. For the latter alternatives the following investigations would be required:

    a. Coal-Fired Thermal Power Generation - Investigate the feasibility of a thermal steam plant using coal supplied from Ridley Island. Examine the cost of coal from the Telkwa and Peace River coalfields. Conduct site selection studies paying particular attention to such details as water supply for boiler feed and condenser cooling, dock facilities for coal barges, ash disposal area, road access etc. Determine the site specific environmental impacts of a small coal-fired thermal plant. Investigate in detail the cost and availability of packaged thermal generating plants and determine

       accurate transportation, and construction costs. Conduct a simulation to determine the impact of future load growth projections on plant economics.

    b. Small Hydroelectric Power Generation - Investigate the feasibility of small hydroelectric power generation at Walker Lake and Lakes A, B, C and D. Conduct an investigation of the impacts on the salmon fishery resulting from the development of Walker Lake and the potential diversion of Lake D. Conduct site investigations at both sites. Develop project layouts including all of the facilities to connect them to the existing power system. Prepare sufficiently reliable cost estimates to permit an investment decision. Specifically the following work should be undertaken:

- develop regional hydrology data to provide simulations of monthly flows at each site,
- collect information on the potential for lake storage,
- determine essential topography by barometric levelling,
- inspect potential intake sites, penstock routes, powerhouse locations and transmission line routes,
- provide preliminary layouts and an estimate of capital costs,
- prepare a report for selecting the best site, and
- install a gauging station at the most promising site and conduct streamflow studies.

OPTIONS DE RECHANGE POUR FOURNIR L'ENERGIE ELECTRIQUE A BAMFIELD ET A BELLA BELLA (C.-B.)

Résumé

La B.C. Hydro a préparé le présent rapport avec l'aide d'Energie, Mines et Ressources Canada qui a fourni 50 % des fonds en vertu du Programme de démonstration dans les collectivités éloignées.

La B.C. Hydro fournit actuellement l'énergie électrique aux collectivités de Bamfield et de Bella Bella ainsi qu'à d'autres collectivités avoisinantes à partir de centrales équipées de diesel situées à Bamfield et à Shearwater. Le coût du carburant diesel a augmenté rapidement au cours des dernières années et par conséquent le coût de production de l'électricité a augmenté au point où d'autres combustibles et d'autres moyens de production d'électricité considérés auparavant comme peu convenables ou peu économiques pour ces collectivités éloignées, pourraient maintenant être rentables.

La présente évaluation préliminaire revoit les moyens utilisés actuellement pour fournir l'électricité aux abonnés de la B.C. Hydro à Bamfield et à Bella Bella et examine les possibilités et les coûts permettant de satisfaire aux besoins actuels et futurs au moyen d'autres sources d'énergie.

Partie A - Bamfield

En 1982-1983 la charge de pointe et la production annuelle d'électricité de la centrale diesel de Bamfield étaient respectivement de 0,65 MW et de 3,14 GW.h. Aux fins du présent rapport, il est supposé que la charge de pointe continuera de s'accroître au taux de 5,3 % par an et la demande d'énergie au taux de 5,0 % par an. La charge de pointe prévue en 1990-1991 serait de 0,98 MW et la consommation de 4,65 GW.h. Il a été supposé aussi que les taux de croissance resteraient inchangés par la suite.

Les coûts estimatifs sont exprimés en dollars de mars 1984. Les chiffres du coût unitaire brut d'énergie correspondent à la charge estimée pour 1990-1991. Aux fins de l'estimation des périodes de récupération, il est supposé que le coût du carburant diesel augmentera au rythme de 1 %, net d'inflation, à partir de 1987-1988, et qu'il augmentera jusqu'alors au même taux que l'inflation.

Une évaluation préliminaire des options de rechange pouvant éventuellement convenir pour Bamfield donne les résultats suivants:

1. Les sources d'énergie qui pourraient fournir des solutions de rechange économiques à la production d'électricité par la centrale diesel à Bamfield:

   a. Petite centrale hydro-électrique à la rivière Sarita

   Le coût de l'énergie produite par une centrale hydro-électrique de

1,0 MW aménagée sur la rivière Sarita, à 19 km de Bamfield, est estimé à 104 millièmes par kW.n. Cette solution pourrait fournir 4,65 GW.h d'électricité en 1990-1991 et jusqu'à 6,1 GW.h par an plus tard lorsque la demande serait plus forte. La capacité de l'installation est limitée par le débit estival faible de la rivière Sarita.

Une petite centrale hydro-électrique ne suffirait pas à satisfaire, seule, à la demande d'électricité à l'avenir et il faudrait une capacité additionnelle fondée sur un matériel diesel pour satisfaire à la demande croissante et particulièrement pour les pointes. Le coût unitaire de l'électricité en 1990-1991 passe à 127 millièmes par kW.h lorsqu'on tient compte de la production additionnelle par matériel diesel. On estime la période de récupération pour la combinaison d'une petite centrale hydro-électrique alimentée au diesel à 19 ans, en fonction d'une mise en service en 1990-1991.

Les répercussions environnementales de l'aménagement d'une petite centrale hydro-électrique ne seraient pas sensibles, parce que le niveau du lac Sarita ne serait point augmenté et que la centrale serait située à la limite supérieure de migration des saumons.

b. Ligne de distribution de Port Alberni (China Creek)

Il a été proposé de construire une ligne de distribution triphasée de 25 kV de China Creek jusqu'à Bamfield. Longue de 73 km, elle suivrait généralement les chemins forestiers existants et serait terminée d'ici 1986-1987. Il est estimé que la ligne offrirait une solution de rechange économique à la production d'électricité par le matériel diesel au coût de 118 millièmes par kW.h en 1990-1991. Le coût est plus élevé que celui de la petite centrale hydro-électrique, mais la ligne de distribution permettrait une croissance considérable de la consommation à un coût unitaire décroissant de l'énergie à l'avenir, tandis que l'option de la petite centrale hydro-électrique n'offre que des possibilités limitées de croissance.

La période de récupération pour une ligne de distribution de China Creek est estimée à 12 ans. La période de récupération pour une ligne de distribution serait nettement plus courte que celle d'une centrale hydro-électrique.

On pourrait construire la ligne de distribution le long de la route d'accès existante de Port Alberni à Bamfield avec peu d'effets environnementaux. Il y aurait quelques pertes de valeurs forestières à cause de l'aliénation de terres.

2. Les sources d'énergie examinées, mais trouvées moins économiques que la production d'énergie électrique par matériel diesel à Bamfield, comprennent l'énergie des marées à Bamfield Inlet, l'énergie éolienne près de la baie Pachena, une centrale thermique alimentée au bois à la baie Roquefeuil, une centrale munie de turbines mues au bois gazéifié à la baie Roquefeuil, une centrale thermique alimentée au charbon à la baie Roquefeuil et les autres combustibles gazeux ou liquides.

Partie B - Bella Bella

La charge de pointe (1982-1983) et la production annuelle d'énergie pour la centrale de Shearwater (Bella Bella) étaient de 1,80 MW et de 7,74 GW.h, respectivement. Aux fins du présent rapport, il est supposé que la charge de pointe continuerait de s'accroître au rythme de 4,5 % et la demande d'énergie à 3,7 %. Par conséquent, en 1990-1991, la charge de pointe serait de 2,55 MW et la consommation annuelle de 10,35 GW.h. Il est supposé aussi que ces taux de croissance resteraient inchangés à l'avenir.

Une évaluation préliminaire des autres sources d'énergie électrique éventuellement disponibles pour Bella Bella donne les résultats suivants:

1. Les sources d'énergie qui pourraient offrir des solutions économiques de rechange à la production d'énergie par matériel diesel à Bella Bella sont:

   a. Petite centrale hydro-électrique au lac Walker

   Une petite centrale hydro-électrique de 1,1 MW aménagée dans le chenal Johnson à l'embouchure qui draine le lac Walker pourrait fournir environ 7,7 GW.h par an en 1990-1991. Cette production suppose un entreposage au lac Walker. Une ligne de distribution de 27 km, y compris 1,5 km de câble sous-marin, serait nécessaire entre la centrale proposée et Shearwater.

   Le coût unitaire brut de l'électricité produite au lac Walker est estimé à 109 millièmes par kW.H. Le coût augmente à 131 millièmes par kW.h (1990-1991) si l'on ajoute le coût de la production supplémentaire par matériel diesel. On estime la période de récupération à plus de 20 ans à cause de la nécessité d'une capacité appréciable de production (probablement par diesel) à l'avenir.

   Les répercussions environnementales découlant d'un petit aménagement hydro-électrique du ruisseau drainant le lac Walker seraient de toute évidence peu importantes. Le saumon ne fraie que dans les 400 m du cours inférieur du ruisseau parce qu'une cascade d'une hauteur de 12 m bloque le passage aux poissons.

   b. Petite centrale hydro-électrique aux lacs A, B, C et D

   Un deuxième site pour un petit aménagement hydro-électrique a été décelé par un rapport établi en 1963 par la B.C. Hydro et se trouve de l'île Denny, à 13 km de Shearwater. Les lacs désignés A, B, C et D fourniraient un débit suffisant pour une centrale de 0,5 MW. Il est estimé que cette petite centrale hydro-électrique pourrait produire jusqu'à 3,5 GW.h par an. Le chiffre proposé suppose qu'il est possible de construire un petit barrage sur le cours supérieur du ruisseau Kajusdus afin de dévier l'écoulement du lac D vers le ruisseau drainant le lac C. Si la dérivation n'était pas possible, il faudrait prévoir une réduction de 15 % de l'énergie.

Il est estimé que le coût unitaire brut de l'énergie produite par un petit aménagement hydro-électrique mettant à profit les lacs A, B, C et D serait de 111 millièmes par kW.h. La période de récupération n'a pas été calculée parce que l'option est légèrement moins économique que celle du lac Walker et parce qu'on n'a pas rendu visite au site lors du voyage à Bella Bella et qu'on ne sait que peu du site.

Il existe d'importantes frayères de saumon dans le ruisseau Kajusdus qui draine le lac D, mais on ne connaît pas les répercussions que produirait sur les pêcheries l'endiguement d'un petit affluent proche des sources. Un impact moins important serait l'effet visuel de la ligne de distribution de 14 km jusqu'à Shearwater.

c. Centrale marémotrice au bassin Hochstader

Il est estimé qu'une centrale marémotrice de 2 MW près de l'entrée du bassin Hochstader pourrait fournir 7 GW.h par an selon un facteur de capacité de 40 %. Le coût unitaire brut de l'énergie en 1990-1991 est estimé à 169 millièmes par kW.h, ce qui est quelque peu plus élevé que celui de la filière diesel et considérablement plus élevé que le coût du combustible diesel. Il serait nécessaire de prévoir un moyen de production de secours parce que l'énergie des marées est intermittente et que l'option ne pourrait servir que de moyen de réduire la consommation de combustible. L'ajout de matériel diesel porte le coût prévu de l'énergie des marées à 176 millièmes par kW.h, ce qui est nettement supérieur au coût de production par matériel diesel.

Les répercussions environnementales de la centrale marémotrice sur le bassin Hochstader seraient peu importantes. Malgré l'existence d'activités de pêche de saumon et de hareng dans le bassin auparavant, il ne s'agissait pas de grands volumes et les pêcheurs ne les exploitent pas maintenant.

d. Centrale thermique alimentée au charbon située à la baie Norman Morrison

Il est supposé que le charbon pourrait se fournir en quantités essentiellement illimitées à partir de l'île Ridley près de Prince Rupert. On estime que le coût livré du charbon serait de 61,45 $ la tonne et que le coût du combustible f. à b. île Ridley augmenterait au rythme de 0,5 % (net d'inflation) à partir de 1990-1991. Le coût unitaire brut de l'énergie produite par une centrale thermique alimentée au charbon, située dans la baie Norman Morrison, est estimé à 150 millièmes par kW.h en 1990-1991.

On a tenu compte aussi du besoin de produire de l'électricité par matériel diesel pour faire face aux charges de pointe et pour fournir une capacité de démarrage après panne. Le coût unitaire brut en est porté à 161 millièmes par kW.h. On suppose que de nouveaux groupes alimentés au charbon seraient ajoutés lorsque la coefficient d'utilisation des anciens atteindrait 75 % et que des groupes électrogènes diesel seraient ajoutés par les pointes. Pour la centrale thermique alimentée au charbon, on estime la période de récupération à plus de 20 ans.

Les répercussions environnementales de l'option charbon seraient peu importantes. Les émissions dans l'air ainsi que les déchets solides produits par la centrale pourraient être contrôlés par des permis émis en vertu de la Loi sur la gestion des déchets de la Colombie-Britanique.

e. Ligne de transport reliant Ocean Falls à Shearwater

Il existe une centrale hydro-électrique à Ocean Falls. Cette centrale a fourni de l'électricité à une fabrique de pâte à papier qui a maintenant fermé ses portes ainsi qu'à la collectivité. Il y a maintenant peu de résidants dans ladite collectivité. On pourrait construire une ligne de transport triphasée de 69 kV, à poteaux en bois pour relier Ocean Falls à Shearwater. Un certain nombre de trajets possibles ont été examinés dans une étude menée par Reid Crowther and Partners Limited. Un de ces trajets, qui comprend 52 km de lignes aériennes et 1,5 km de lignes sous-marines a été choisi pour les besoins du présent rapport.

Le présent rapport examine le coût de l'énergie à Bella Bella seulement, et ne suppose rien quant à l'appartenance des installations entre Shearwater et Ocean Falls. On estime le coût unitaire brut de l'énergie à 100 millièmes par kW.h (1990-1991), ce qui représente l'option la plus économique de celles qui ont été examinées pour Bella Bella. On suppose qu'il ne serait pas nécessaire de prévoir des groupes de secours au diesel, bien qu'il soit peut-être nécessaire de prévoir une certaine capacité de production au diesel pour assurer la sécurité d'approvisionnement pendant les premières années d'exploitation et peut-être plus tard aussi. On estime la période de récupération à 10 ans.

Les répercussions environnementales d'une ligne de transport reliant Ocean Falls à Bella Bella proviendrait principalement de la construction et de l'aliénation de terres. Pendant la phase de construction, le franchissement des ruisseaux pourrait causer une certaine turbidité. Il faudrait aliéner des superficies considérables de terres et les valeurs forestières seraient touchées. De plus, l'effet visuel d'une coupe linéaire dans la fôret pourrait avoir un impact important.

2. Les sources d'énergie examinées qui seraient moins économiques que la production d'énergie par la filière diesel à Bella Bella comprennent l'énergie éolienne au mont Hand, une centrale thermique alimentée au bois à la baie Norman Morrison, une centrale munie de turbines mues au bois gazéifié à la baie Norman Morrison et d'autres combustibles gazeux ou liquides.

Recommandations

Cette évaluation préliminaire permet les recommandations suivantes:

1. La B.C. Hydro pourrait continuer à fournir l'énergie électrique à Bamfield et aux collectivités environnantes par la filière diesel, mais le coût serait élevé. Il est recommandé que la B.C. Hydro mette en oeuvre le plan d'intégrer Bamfield au réseau en construisant une ligne de distribution triphasée de 25 kV à partir de Port Alberni. Cette option sera

certainement économique avant l'année 1990-1991 utilisée comme année de base pour le présent rapport. L'aménagement d'une petite centrale hydro-électrique pourrait représenter une option intéressante pour la production d'électricité sur place, mais elle est moins économique que l'intégration et elle ne devrait être examinée d'avantage que si la ligne de distribution s'avère insuffisante pour la charge à l'avenir.

2. La B.C. Hydro pourrait aussi continuer à fournir l'électricité à Bella Bella et aux collectivités environnantes à l'aide de matériel diesel, mais le coût serait élevé. Il est recommandé que la B.C. Hydro continue d'examiner la faisabilité de fournir l'électricité à Bella Bella au moyen d'une ligne de transport triphasée de 69 kV à partir d'Ocean Falls. Cette option serait la plus économique en 1990-1991 utilisée comme année de base. Si cette option n'était pas faisable, les méthodes de production d'électricité sur place qu'il convient d'examiner sont la centrale thermique alimentée au charbon et la petite centrale hydro-électrique.

1.0 INTRODUCTION

B.C. Hydro operates and maintains non-integrated generating stations which supply power to 15 communities in British Columbia (Diesel Apparatus Department, B.C. Hydro). These generating stations are powered by diesel and gas turbine generating units primarily burning diesel fuel, although natural gas is the prime fuel burned at Fort Nelson. The stations range in size from 1.0 MW of installed capacity at Telegraph Creek to 25.8 MW of installed capacity at Fort Nelson. Diesel generating stations are normally decommissioned as the communities are connected to the integrated system. Three stations are being maintained for stand-by service in order to provide security of supply in case of a transmission line disruption.

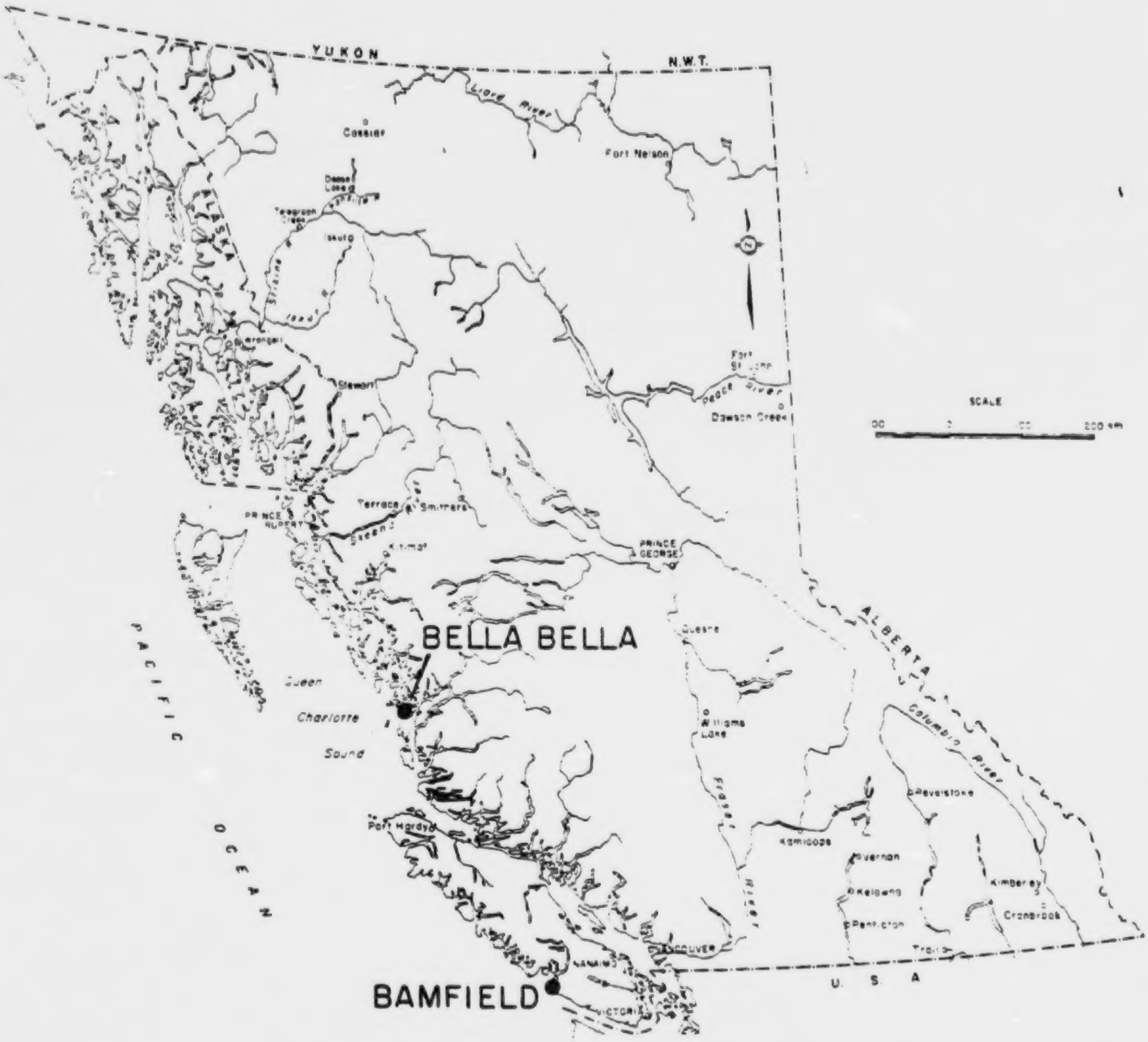
The cost of diesel fuel and the resulting cost of electrical generation escalated significantly beginning in 1973 and particularly rapidly beginning in September 1980 (Diesel Apparatus Department, B.C. Hydro). The cost began decreasing in September 1982, but this condition was anomalous and since March 1983 the price has increased markedly at Bamfield and moderately at Bella Bella. The fuel prices are expected to increase significantly as the world economy improves.

This report describes the existing diesel electrical power generation at Bamfield and Bella Bella and compares it to the alternative energy options and transmission from outside sources. In addition, the report briefly describes the technologies which could be used to exploit these options.

Bamfield and Bella Bella were selected as sites for examining alternative energy options because they are two of the major consumers of diesel fuel on the outer coast of British Columbia (Fig. 1-1). Stewart, Masset, and Sandspit have larger diesel fuel consumptions than either Bella Bella or Bamfield. However, Stewart is well away from the outer coast, so fewer alternatives are available. A study of alternative energy options for Masset and Sandspit was completed in 1983.[1] Bella Coola has a larger fuel consumption than Bamfield, but it has significant small hydro potential, and a small hydro development is already in place.

The major part of the report is separated into the following parts:

1. alternative energy options for Bamfield,
2. alternative energy options for Bella Bella,
3. appendices describing the alternative energy technologies, economic parameters, energy costs and a glossary.


YUKON
N.W.T.
ALASKA
Cassiar
Liard River
Fort Nelson
Dease Lake
Telegraph Creek
Iskut
Stikine River
Wrangell
Stewart
Fort St. John
Peace River
Dawson Creek
SCALE
0 100 200 km
Terrace
Smithers
PRINCE RUPERT
Skeena
Kitimat
PRINCE GEORGE
ALBERTA
Quesnel
BELLA BELLA
Queen Charlotte Sound
PACIFIC OCEAN
Williams Lake
Columbia River
Fraser River
Revelstoke
Port Hardy
Kamloops
Vernon
Kelowna
Penticton
Kimberley
Cranbrook
Trail
VANCOUVER
NANAIMO
BAMFIELD
VICTORIA
U. S. A

B.C. HYDRO

Figure 1-1

LOCATION MAP
BAMFIELD-BELLA BELLA

2.0 TERMS OF REFERENCE

(a) Introduction

The Terms of Reference for this study of alternatives to local diesel electrical generation at Bamfield and Bella Bella are dated 15 November 1983.

(b) Objective

The objective of the study is to examine the alternatives to local diesel generation for supplying electrical power to Bamfield and Bella Bella, and to compare these in terms of their costs and benefits to transmission from more distant sources. The ultimate objective is to reduce the use of diesel fuel.

(c) Scope of Work

The following tasks will be completed and their progress reported in brief monthly reports:

1. Summarize the present costs of the existing diesel generating system and also costs for any proposed expansion based on present load growth projections.

2. Summarize the results from the report by Reid Crowther and Partners Limited on supplying hydroelectric power from Ocean Falls to Bella Bella.

3. Summarize the results from the report by B.C. Hydro on supplying electrical power to Bamfield from the Vancouver Island grid.

4. Analyze and describe the tidal, wave, small hydro, biomass, coal and wind resources which are available in the areas. For each of these determine a preliminary suitable location for electrical generating facilities. Describe any serious engineering or environmental constraints which could affect the utilization of the resources. Develop capital cost estimates as well as estimates for the overall cost of electrical power from each of the potential options. Estimate the earliest in-service date for each potential option.

5. Provide an interim report outlining as a minimum the results of the alternative resource evaluation and the environmental examination.

6. Compare the costs of the potential options with the previous estimates for diesel generation and transmission.

7. Recommend a course of action for supplying electrical power to Bamfield and Bella Bella.

8. Determine the cost/benefit implications of postponing or eliminating the need for integration, and demonstrate means by which such can be determined for other remote communities across Canada.

9. Where appropriate, outline a program for a feasibility study (studies) on options which could be economical substitutes for diesel generation and transmission.

10. Provide a draft final report for review by both parties to this agreement.

11. Prepare a final report which shall include as a minimum:
    a. table of contents,
    b. summary or abstract,
    c. introduction,
    d. technical discussion,
    e. findings and conclusions, and
    f. bibliography and/or references.

12. Submit completed report in one reproducible original and ten copies.

13. Representatives of the project team shall, if requested, meet with the communities of Bamfield and/or Bella Bella after study completion to explain the study.

The interim report shall be completed on or before 24 February 1984. The draft report shall be completed on or before 30 April 1984, and the final report shall be completed on or before 31 May 1984. (Note: an extension was obtained to permit completion on or before 30 June 1984.)

In addition, B.C. Hydro should inform the EMR Conservation and Renewable Energy Office in Burnaby of its progress on the study in writing before the last day of each month, during the duration of the project.

3.0 ECONOMIC PARAMETERS

The economic parameters are described in detail in Appendix C. The effective date of the cost estimates used in this study is 31 March 1984. Inflation estimates for fiscal years ending 31 March are based on the following composite values which are used by B.C. Hydro:[2]

Percent Change[*1]

Year Ending 31 March	Generation-Hydro	Distribution	Transmission	Transformer-Substation	Generation Thermal	Total Fixed Asset Composite Inflator
1974[*2]	12.1	12.1	11.5	10.8	11.6	11.8
1975	17.3	18.6	19.2	21.2	18.2	18.2
1976	12.8	10.7	14.8	14.7	13.6	13.1
1977	8.1	6.0	7.7	7.5	10.2	7.6
1978	6.5	6.6	7.6	4.8	8.2	6.5
1979	7.9	9.0	9.6	8.2	8.6	8.4
1980	9.2	14.1	14.1	10.4	10.1	10.9
1981	10.8	12.9	12.8	10.1	11.2	11.2
1982	12.0	9.1	10.1	7.3	10.5	10.3
1983[*3]	7.5	9.0	6.0	11.0	7.5	8.0
1984[*3]	5.5	6.0	6.0	5.5	5.5	5.5

[*1] The weightings for the specific fixed asset categories vary according to B.C. Hydro's actual or anticipated expenditures.

[*2] Historical inflators for fiscal years 1974 to 1982.

[*3] Forecasts are rounded to the nearest 0.5 percent.

Energy costs are estimated at the following discount rates (net of inflation): 4, 6, 8 and 10 percent (Appendices C, D and E). B.C. Hydro is presently using a 4 percent net discount rate. Interest during construction (I.D.C.) is calculated on the project cost including engineering, contingencies and corporate overhead. I.D.C. is applied where the construction period is more than 1 year. I.D.C. is based on a series of construction schedules derived for various types and sizes of alternatives and it is calculated at 4, 6, 8 and 10 percent net of inflation.

Corporate overhead is assumed to be 9 percent for all projects examined in this study. Corporate overhead is calculated on the project cost including engineering and contingencies, but excluding I.D.C.

Contingencies vary with the degree of uncertainty of the cost estimates. The contingencies are estimated as a percentage of the construction cost including engineering, but before the addition of corporate overhead and I.D.C.

For each alternative, part of the operating, maintenance and other variable costs vary directly with the quantity of energy produced.

Fixed operating and maintenance costs are estimated as a percentage of the construction cost including engineering and contingencies, but excluding corporate overhead and I.D.C. The percentage varies for each alternative (Appendix C).

The life for plants and transmission lines vary with the alternative and are those used by B.C. Hydro.

For this study cost comparisons are made on the basis of gross unit energy costs.

4.0 REFERENCES

[1] System Engineering Division. 1983. Queen Charlotte Islands power supply preliminary evaluation. B.C. Hydro Report No. SE 8106.

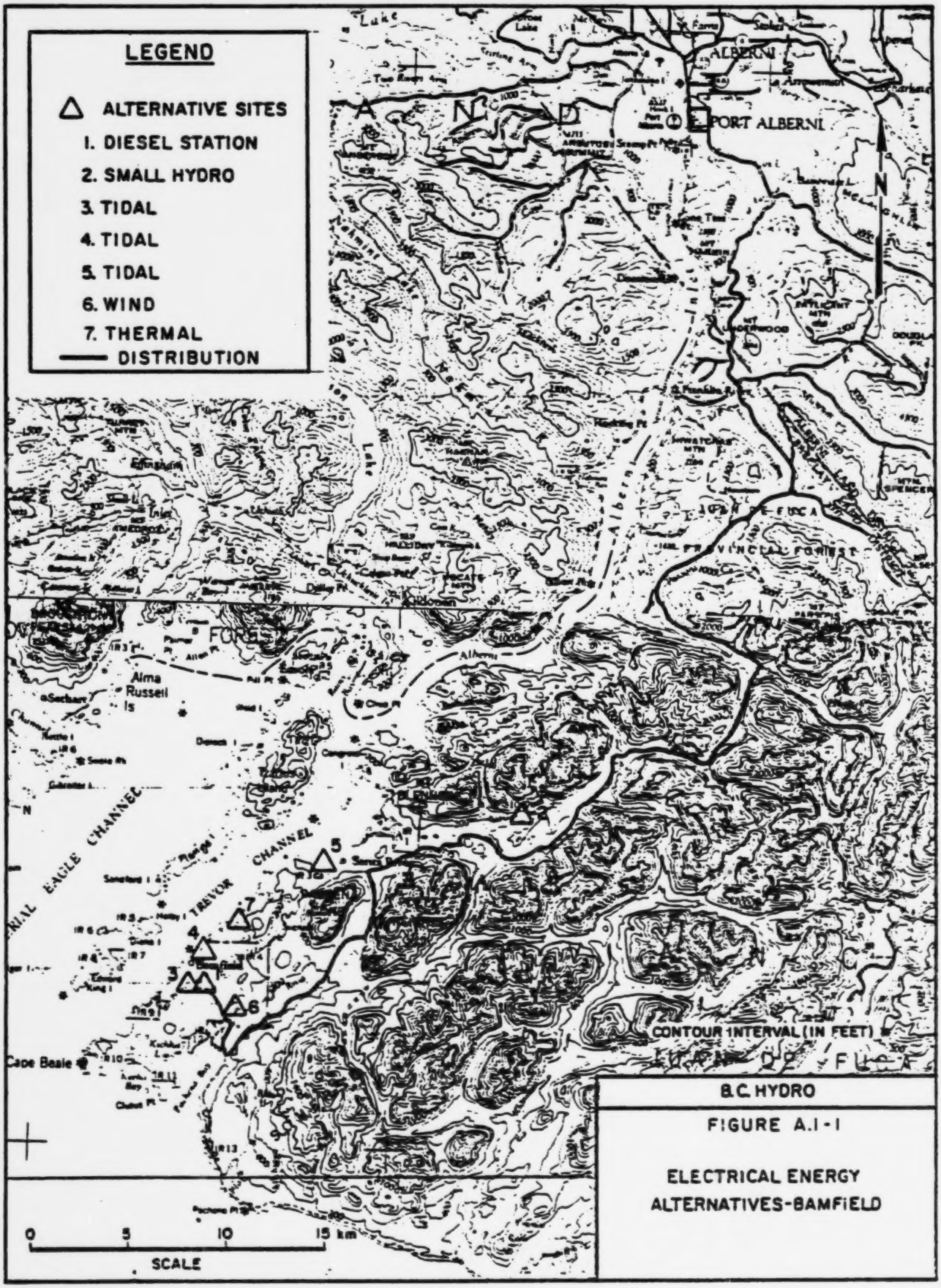
[2] Strategic Planning Unit. 1983. B.C. Hydro Inflation Factors. B.C. Hydro Report.

PART A: ALTERNATIVE ENERGY OPTIONS FOR SUPPLYING ELECTRICAL POWER TO BAMFIELD

SECTION 1.0 - INTRODUCTION

Bamfield is on the west coast of Vancouver Island, southeast of Trevor Channel (latitude 48°50'N and longitude 125°08'W). Bamfield is 87 km by gravel road from Port Alberni (Fig. A.1-1). The terrain consists of rounded hills which rise to as much as 906 m, southwest of Sarita Lake. The hills are lower and more gently sloping near Bamfield.

The possibility of establishing a central generating station at Bamfield was examined by the B.C. Power Commission as far back as 1946.[1] In 1959 the B.C. Power Commission re-examined the electrical requirements of Bamfield.[2] At that time the community relied on individual gas-powered generators ranging in size from 1 kW to 15 kW. In addition to these generators the Canadian Overseas Telecommunication Corporation had a powerhouse at Bamfield, but their facilities were soon moved to Port Alberni. In 1971 the Western Canadian Universities Marine Biological Station had a report prepared to outline requirements for electrical generation at their facility which had a total peak demand of 52 kW.[3] By 1972 the marine station had an approximate peak demand of 80 kW and an annual energy of 52 MW·h and the village had an approximate peak demand of 70 kW and an annual energy of 39 MW·h.[4] The Bamfield Utilities Company was generating electricity for the community; they had one 85 kW Caterpillar D17000 and one 96 kW Caterpillar D17000. This diesel generating plant was acquired by B.C. Hydro in August 1972 and Mr. R. Ostrom was hired as agent. Two mobile diesel generating units with a capacity of 1000 kW were installed in late 1972.[5] By 1983 there were three trailer units consisting of two 600 kW units and one 500 kW unit.


LEGEND
△ ALTERNATIVE SITES
1. DIESEL STATION
2. SMALL HYDRO
3. TIDAL
4. TIDAL
5. TIDAL
6. WIND
7. THERMAL
DISTRIBUTION
ALBERNI
PORT ALBERNI
N
Alma Russell Is
EAGLE CHANNEL
TREVOR CHANNEL
Cape Beale
1
2
3
4
5
6
7
CONTOUR INTERVAL (IN FEET)
0
5
10
15 km
SCALE

B.C. HYDRO

FIGURE A.1-1

ELECTRICAL ENERGY ALTERNATIVES-BAMFIELD

SECTION 2.0 - PLANT SITE SELECTION

The selection of the site for an electrical generating plant is influenced by many factors including the nature of the energy source, transportation costs, transmission costs, location of the load centre and environmental factors.

For this preliminary report on supplying electrical power to Bamfield, a location south of Dixon Island on Roquefeuil Bay was selected as the site of a possible thermal plant (Fig. A.1-1).

This site was selected for the following reasons:

1. The terrain is moderate.
2. The site is close to the ocean which may be used as a source of cooling water and a site for docking facilities.
3. Coal could be brought to the site by barge.
4. The site is away from Pacific Rim National Park and from residences.
5. Approximately 6 km of new distribution line would be required to connect this possible plant site to the 3-phase distribution line.

Disadvantages of the site are that it is not close to existing roads and there is little fresh water available for boiler make-up.

The sites for hydroelectric, tidal and wind power tend to be site specific and governed by the availability of the resources. The proposed small hydroelectric site is on the Sarita River approximately 8.5 km from its mouth and 18.5 km northeast of Bamfield. The proposed tidal site is within Bamfield Inlet and across the north ends of Rance and Burlo islands. The proposed wind site is on an unnamed hill southeast of Bamfield and northwest of the Pachena River. This hill is over 100 m high and has a broad flat-top which is oriented northeast-southwest. Each of these sites is described in detail in the appropriate section of this report.

The sites were selected only for making cost estimates. A detailed site selection study would be required at an early stage of any subsequent study.

SECTION 3.0 - EXISTING FACILITIES

In March 1984 the facilities at Bamfield consisted of the following mobile diesel generating units (J.S. Wong, System Planning Department, B.C. Hydro, personal communication):

	kW
1 x 500 kW (Cat. D398)	500
2 x 600 kW (Cat. D398)	1200
Total generating capacity	1700

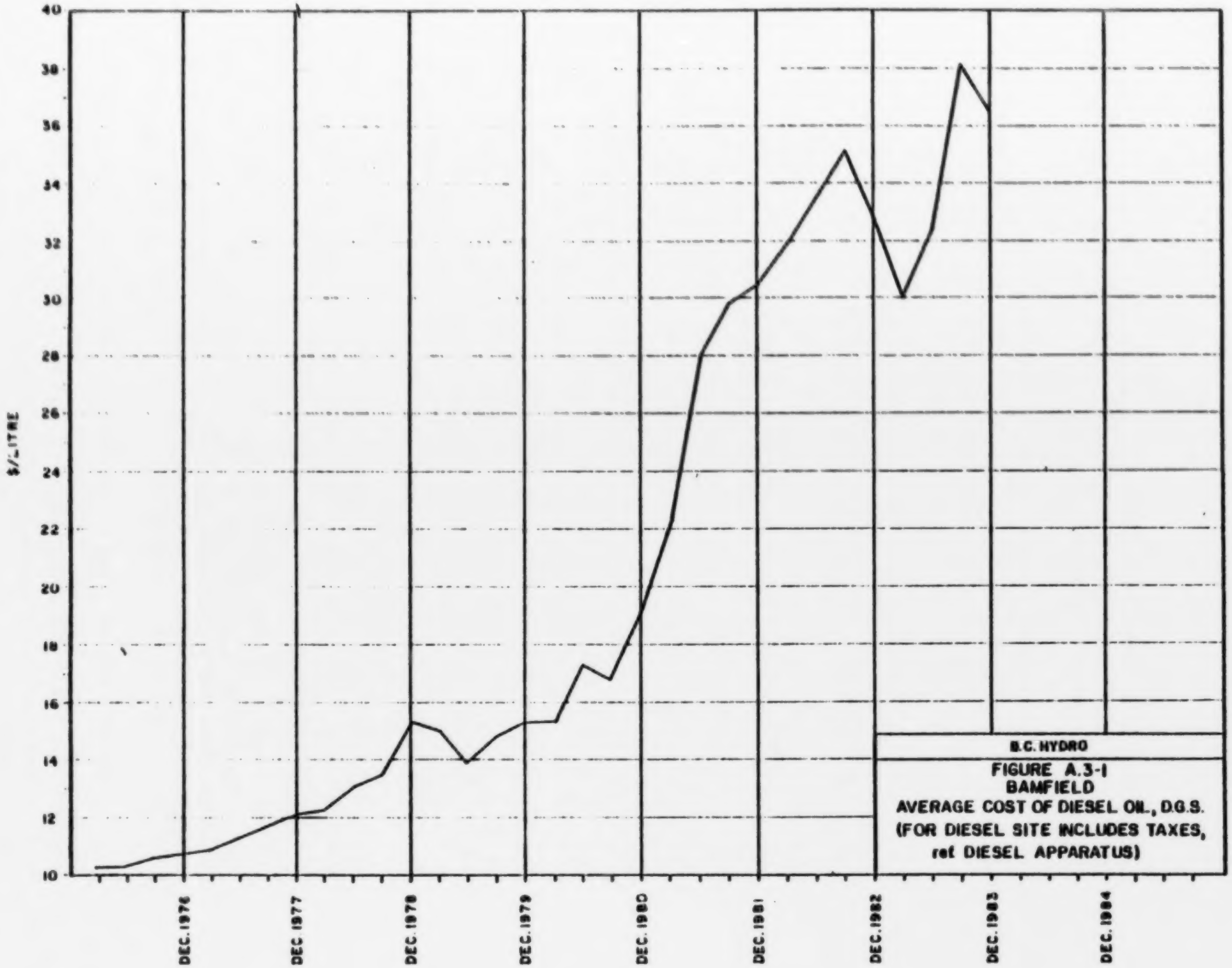
For diesel generating stations which are off the grid, it is the policy of B.C. Hydro to have sufficient capacity to meet the peak load with the largest unit out-of-service. Therefore, the firm generating capability of the Bamfield Generating Station is 1100 kW.

The diesel generating station has accommodated mobile units ranging in size from 150 kW to 600 kW. Semi-mobile generating units in 1000 kW and 2500 kW sizes could be installed at the site if necessary. The station is semi-automated and is operated and maintained on a part-time basis by a local agent. Diesel fuel for the station is delivered by tank truck and is stored on site in two storage tanks having a total capacity of 76 000 L.

The peak load for the Bamfield Generating Station in 1982/83, the last reporting year, was 650 kW (Diesel Apparatus Section, B.C. Hydro, Monthly Report, March 1983) and the annual energy for 1982/83 was 3.14 GW·h. This station supplies electrical power to Bamfield (including Grappler Inlet), the Anacla Indian Reserve No. 12 and Pachena Bay.

The primary distribution system from the generating station to much of Bamfield is 25 kV, 3-phase (G. Jackson, V.I. Distribution Engineering Department, B.C. Hydro, personal communication). Distribution to residential areas is mostly 14.4 kV and single-phase. A 4.16 kV, 3-phase aerial line via Rance and Burlo islands and a 12 kV submarine cable (operated at 4.16 kV) connect the east and west sides of Bamfield Inlet. Some parts of west Bamfield are not connected to the B.C. Hydro system. A single-phase, 14.4 kV line extends from the diesel generating station to the Anacla Indian Reserve No. 12 and Pachena Bay.

The cost of diesel power increased dramatically from 1976 to 1983 because of the escalating cost of crude oil. The average costs of diesel fuel for the Bamfield Generating Station are illustrated in Fig. A.3-1, (Diesel Apparatus Department, B.C. Hydro). In March 1976 the average price of diesel fuel was $0.103/L whereas the cost reached a



B.C. HYDRO

FIGURE A.3-1
BAMFIELD
AVERAGE COST OF DIESEL OIL, D.G.S.
(FOR DIESEL SITE INCLUDES TAXES,
ref DIESEL APPARATUS)

peak of $0.380/L in September 1983 and decreased to $0.365/L by December 1983.

World economic recovery is expected to increase the price of diesel fuel, but these increases will probably be more moderate than in the recent past. Future increases in the cost of diesel fuel are also expected because of Canada's National Energy Policy which should continue to move the cost of oil in Canada toward world prices. World prices have decreased during the recession, whereas Canada's selling price has been fluctuating, but generally increasing.

The present load serviced by the B.C. Hydro generating station at Bamfield is both residential and commercial. There are 151 customers in the Bamfield area.[6] The population statistics for the Bamfield area, including Bamfield, Grappler Inlet, the Anacla Indian Reserve No. 12 and Pachena Bay, which are supplied by the Bamfield Generating Station, are as follows: (Statistics Canada - 1981 Census)

Bamfield	211
Anacla	74
Pachena Bay	188
Total	473

The population is affected significantly by tourists and the regular influx of students and researchers to the Western Canadian Universities Marine Biological Station. The fishing activities, winter electrical heating and summer tourist trade all affect the load at different seasons; therefore, the load peaks each day at approximately 600 kW.

SECTION 4.0 - FUTURE POWER REQUIREMENTS

Projections of load requirements from 1982/83 to 1990/91 are estimated in Table A4-1. These estimates assume that there are no increases in industrial load and no substantial increases in residential load due to industrial development. There are no plans for installation or removal of diesel generating units prior to 1986/87 (J.S. Wong, System Planning Department, B.C. Hydro, personal communication). It has been proposed that Bamfield be integrated with the island grid by means of a 25 kV distribution line from Port Alberni by 1986/87. It is presently proposed that the diesel generating station be removed at that time provided the new distribution line is secure.

TABLE A4-1

PROJECTION OF GROSS LOAD REQUIREMENTS
AND LOAD GROWTH FOR BAMFIELD*

	Peak	Energy
Actual Load 1982/83	0.65 MW	3.14 GW·h
Growth 1982/83 to 1990/91	5.3%	5.0%
Projected Load 1990/91	0.98MW	4.65 GW·h

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* J.S. Wong, System Planning Department, B.C. Hydro, personal communication.

SECTION 5.0 - ENERGY RESOURCES AND SUPPLY

5.1 INTRODUCTION

The following subsections list the known energy sources which are available in the Bamfield area and assess them as possible power sources for the B.C. Hydro system. These sources are diesel and alternative fuels, small hydroelectric, wave, tidal, wind, wood waste, tree farms, peat, municipal solid waste, coal, geothermal and transmission (Fig. A.1-1).

5.2 DIESEL AND ALTERNATIVE FUELS

Diesel fuel is presently brought to Bamfield from refineries in Vancouver. The use of diesel fuel in diesel-powered electrical generating units is well established technology with a wide range of unit sizes. These units can be installed quickly and many of the units are mobiles which allows them to be moved to the B.C. Hydro Diesel Shop in Surrey for overhaul or major repairs. Standby mobile generating units are readily available to replace units removed for repair or to increase station capacity on short notice.

The Bamfield system includes three such mobiles and no stationary units. These units burn No. 2 fuel oil. Fuel oil prices have been very volatile and unpredictable since June 1980 (Fig. A.3-1). It is expected that economic recovery will result in upward pressure on diesel fuel prices.

An alternative fuel may be more economical for the existing generating facilities at Bamfield. These alternative fuels are low sulphur crude oil, residual oil, propane, butane, low-Btu gas, compressed natural gas (CNG), liquid natural gas (LNG), condensate and alcohols (J.S. Foster, Diesel Apparatus Department, B.C. Hydro, personal communication).

Both crude oil and condensate would be potential fuels for the diesel generating station; however maintenance costs would be expected to increase as much as 100 percent. In addition, suppliers are reluctant to provide crude oil because it is too valuable as a refinery feedstock. The light ends tend to be very toxic and flammable and the quality is variable. Therefore, crude oil is unlikely to be a suitable fuel. The problem with using condensate is that the quality is also variable and a specification cannot be written for it.

Residual oil would not be an acceptable fuel for the present diesel generating station. Residual oil requires heating, and maintenance costs could be 200 to 1000 percent higher than maintenance costs for diesel fuel depending on the viscosity of the residual oil.

Propane, CNG and LNG would be good fuels for the diesel generating units. However, derating of the generating capacity of the units would be required. This derating would be approximately 25 percent for propane and 15 percent for natural gas. Propane is a dangerous fuel because it is heavier than air and in the event of leaks it tends to collect in low areas. CNG and LNG are excellent fuels, but transportation, storage and handling would present serious problems.

Butane and low-Btu gas would be unacceptable fuels for the present diesel generating units at Bamfield. Butane has a low vapour to liquid pressure and its octane equivalent is low making it a poor fuel. The problem with low-Btu gas is getting sufficient fuel into the combustion chamber of the existing units to provide useful mechanical energy.

Brazil produces ethanol from bioresources. The United States and West Germany are examining the production of methanol from coal.[7] Alcohols can be and are used in internal combustion engines, but these fuels cause misfiring and knocking. Two alternatives are being examined to resolve this problem. One method is the addition of 10 percent suitable solubilizers which would allow a maximum of 25 percent ethanol and 9 percent water. The second method uses specially designed carburetion and an ignition accelerator additive to permit burning a maximum of 80 percent ethanol. Ethanol differs from diesel fuel in that the heat of vaporization of ethanol is higher by a factor of three, the boiling point of ethanol is lower by a factor of one-half to one-fifth, the ignition temperature of ethanol is 100°C higher and the heating value of ethanol is 63 percent that of diesel fuel. The overall effect is an ignition lag extension when using ethanol and this effect must be corrected to permit extensive use of this fuel.

Therefore, it is unlikely that any other fuels could be used as alternatives to No. 2 diesel fuel oil in the present diesel generating facilities at Bamfield.

5.3 SMALL HYDROELECTRIC

(a) Introduction

A field reconnaissance survey was made of the area within a 20 km radius of the community of Bamfield. Map studies indicated that the only potential site close to the community and suitable for meeting the projected load demand was located on the Sarita River which drains the Sarita Lake (Fig. A.5-1). Although access was difficult, this site was examined on foot and on the basis of a visual evaluation appeared to be promising. Another potential site on the lower part of the Little Nitinat River was not included (or examined) in this study due to the extensive length of transmission line that would be required. Refer to Appendix A for a description of small hydro technology.

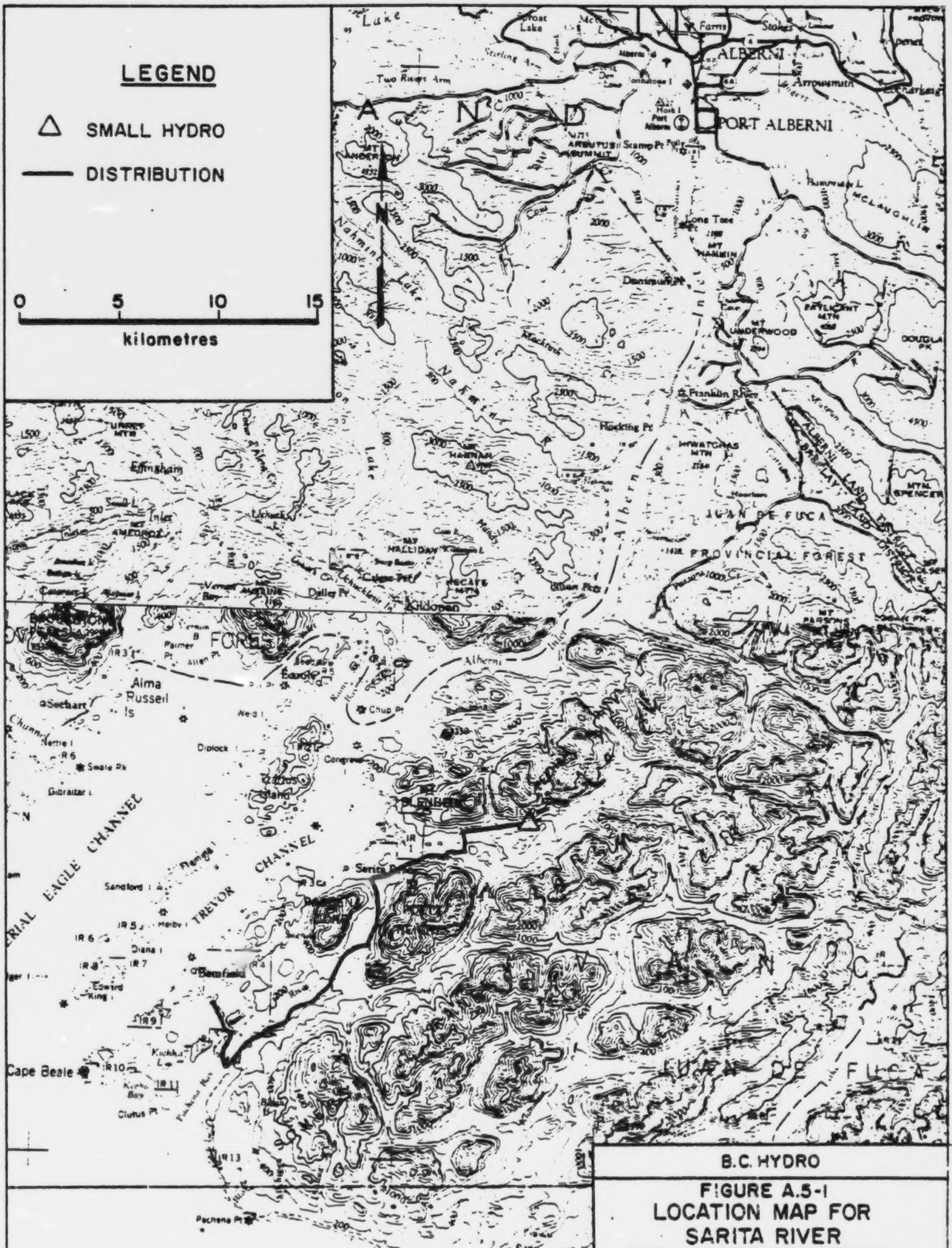

LEGEND
△ SMALL HYDRO
DISTRIBUTION
0
5
10
15
kilometres
ALBERNI
PORT ALBERNI
Sproat Lake
Two Rivers Arm
Stamp Pt
Lone Tree
MT HANKIN
MT UNDERWOOD
Franklin River
Hocking Pt
MT HALLIDAY
Effingham
Kildonan
Alma Russell Is
Sechart
Diplock I
Congreve I
Chup Pt
Sarita
TREVOR CHANNEL
IMPERIAL EAGLE CHANNEL
Bamfield
Cape Beale
Pachena Pt
PROVINCIAL FOREST
JUAN DE FUCA
B.C. HYDRO

FIGURE A.5-1
LOCATION MAP FOR
SARITA RIVER
SMALL HYDRO ELECTRIC
BAMFIELD, B.C.

(b) Site Description

The Sarita River site is located at the western end of Sarita Lake (Fig. A.5-2) where the lake outlet flows through a series of rapids and waterfalls (Figs. A.5-3, and A.5-4). The site location appears to be ideal because full advantage can be taken of the 43 m drop in elevation from the lake to the base of the falls. In addition, the deep and narrow outlet from the lake and the configuration of this section of the river are well suited for a small hydro development.

Hydrology

The catchment basin which provides the inflow into Sarita Lake is more than 90 km^2 in area (Fig. A.5-2). The lake is at an elevation of 55 m and it is surrounded by steep terrain rising to more than 900 m. The basin lies in a zone of high precipitation with few temperature extremes and it is subject to the prevailing westerly winds. Therefore, runoffs are heavy and rapid, resulting in sudden increases in the lake level and flooding around its perimeter.

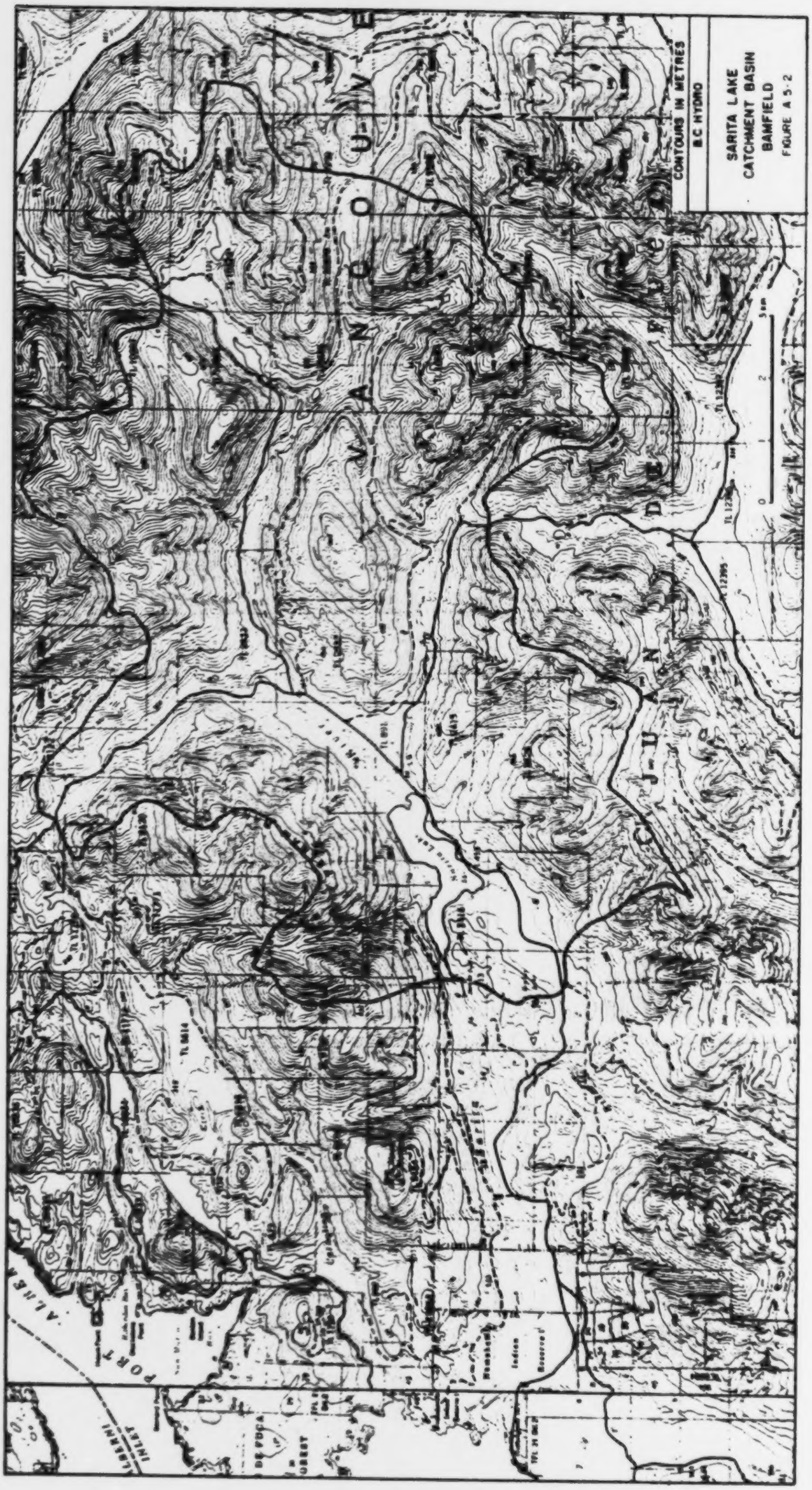
Thirty four years of records are available for the combined flows of the Sarita and South Sarita rivers, the confluence of which is about 5 km downstream from the proposed site.[8] On the basis of this extensive data and the size of the catchment basins, it is estimated that the mean annual flow from Sarita Lake is in the order of 11 m^3/s. Records show that maximum flows occur during the winter period which reflects the influence of the precipitation pattern over the area and the small accumulation of snow pack at higher elevations.

(c) Power Studies

It is apparent that due to the low topography of parts of the lake perimeter and the close proximity of the main road to Bamfield it would be difficult to provide any substantial storage on Sarita Lake. A low weir-type structure at the head of the rapids may prove to be feasible and provide some storage potential, but for the purpose of this study, development of the site has been considered on a "run-of-the-river" basis only with no flow regulation.

The annual energy capability of the site considerably exceeds the required scale of development. Plant sizing has been based on the forecast peak load for the area in the early 1990s and it is estimated that 1 MW of generating capacity would meet these requirements.

Without flow regulation and storage, generation is dictated by the availability and distribution of stream flow. Extrapolation from records indicates that, with the exception of the mid-summer period, the outflow from Sarita Lake exceeds by a large margin the



CONTOURS IN METRES

B.C HYDRO

SARITA LAKE
CATCHMENT BASIN
BAMFIELD
FIGURE A 5·2

VANCOUVER
JUAN DE FUCA
PORT
ALBERNI INLET
0
2
3 km

FIGURE A.5-3 Sarita Lake outlet with penstock intake location on right side

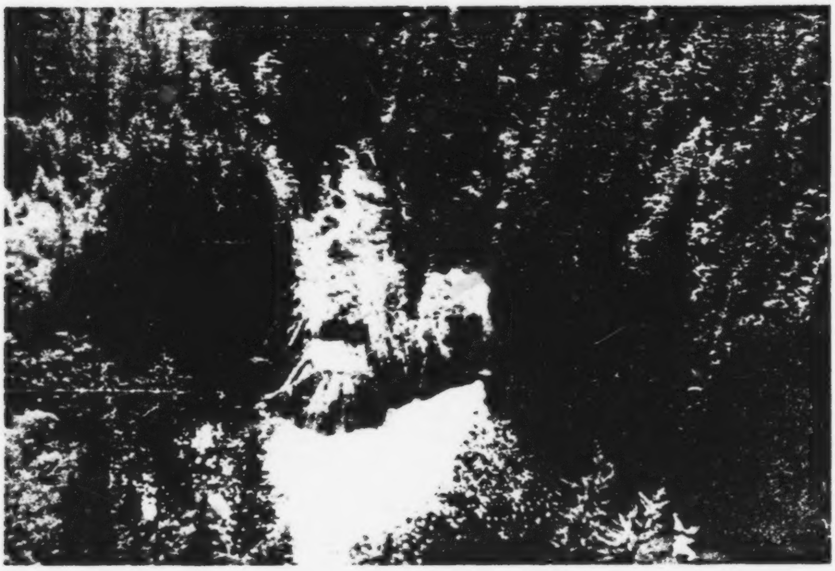


FIGURE A.5-4 Lower Sarita Falls with powerhouse location on left side of falls

design flow requirements of a 1 MW plant. The low flows during the summer are likely to limit generation to two-thirds of capacity over a period of 2 months. This is not considered to be significant in overall energy generation, but would affect the ability of the hydroelectric plant to meet peak loads at that time of year.

During operation the output from the plant could be considerably less than its generating potential. This is attributable to a combination of factors such as flow limitations, the mismatch of generation to load and maintenance and equipment outages. With an allowance of 30 percent for such losses it is conservatively estimated that average annual energy generation would not be less than 6.13 GW·h.

This value is likely to be conservative, but because it exceeds projected energy requirements by more than 30 percent it is of interest only as a means of evaluating long-term economic benefits.

(d) Project Arrangement

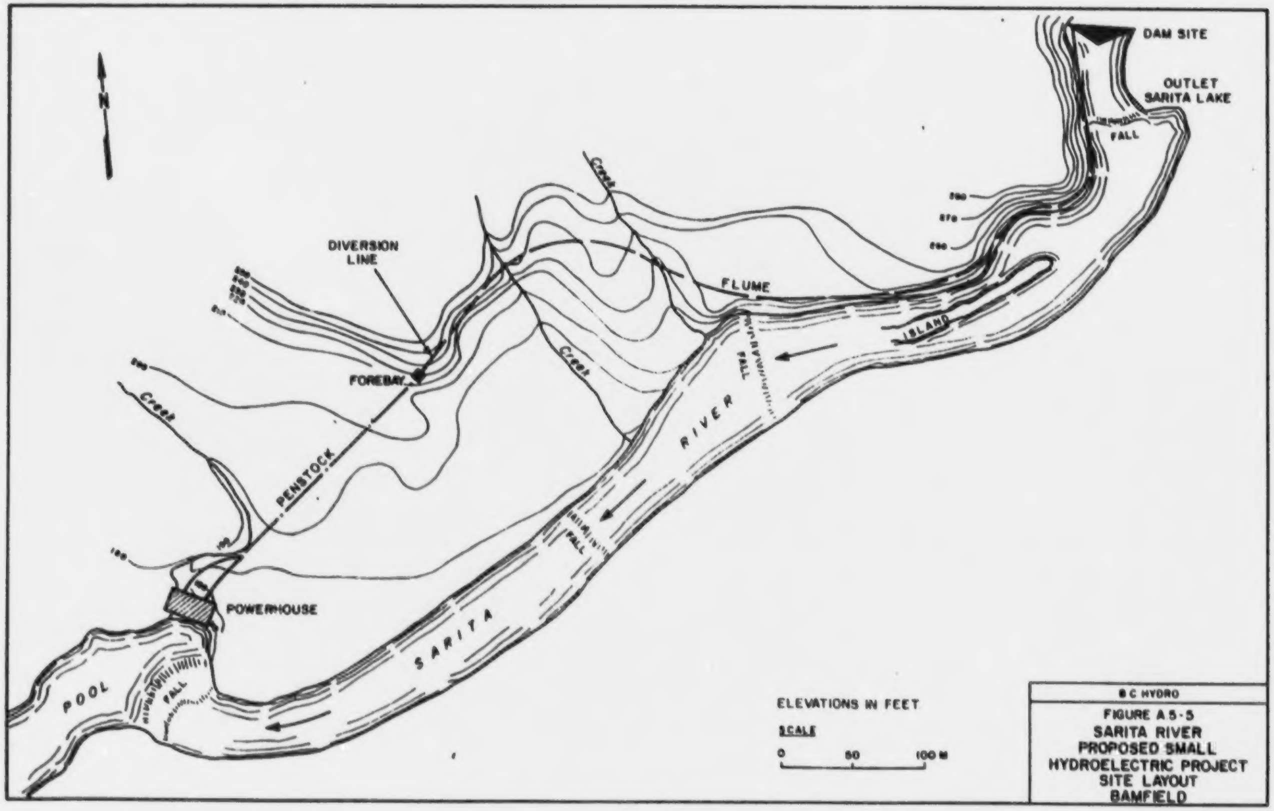
The recommended layout of the Sarita Lake project is shown in Fig. A.5-5. Ground surveys would be necessary to determine the best routing of the penstock and access road and the location of the principal components. Due to the general topography of the area and the position of the lake outlet and river, the north side of the river is preferred for this development which would include the following features:

1. A water intake structure would be constructed on the north bank of the lake outlet, just upstream from the start of the rapids. The lake outlet is long and narrow and appears to be deep which would facilitate the diversion of water. No dam or weir-type of structure across the outlet would be required.

   Trash racks would be required on the intake to avoid blockage due to floating debris. A settling tank is unlikely to be necessary due to the upstream effect of the lake.

2. A penstock or penstock/flume would be laid above ground possibly on an elevated trestle support system to avoid undue excavation. For ease of installation and economic considerations the penstock would be in polyethylene material with a diameter of 600 mm. The overall length of the penstock/flume would be approximately 900 m.

3. The steel-framed powerhouse would contain a single 1000 kW turbine/generator unit. The powerhouse would be sited on the river bank and it would discharge into the natural pool at the base of the lowest water fall.


N
DAM SITE
OUTLET
SARITA LAKE
FALL
280
270
260
ISLAND
FLUME
Creek
Creek
FALL
RIVER
DIVERSION
LINE
FOREBAY
Creek
PENSTOCK
FALL
SARITA
POWERHOUSE
FALL
POOL
ELEVATIONS IN FEET
SCALE
0
50
100 M

B C HYDRO

FIGURE A 5-5
SARITA RIVER
PROPOSED SMALL
HYDROELECTRIC PROJECT
SITE LAYOUT
BAMFIELD

4. A transformer station would step up the generated voltage from 2.4 kV to 25 kV.

5. A distribution line 23 km long would tie the hydro plant into the existing B.C. Hydro line serving Pachena Bay. The line would follow existing logging roads and the highway to Bamfield in order to facilitate the construction and maintenance.

6. An access road to the powerhouse and intake structure would be required. The use of an existing logging road on the lower slopes of the Pelman Range which runs close to the river would be feasible if it was upgraded. A 1 to 2 km long connecting road into the site would be required.

(e) Environmental

The lower part of the Sarita River and its tributaries is an extensive salmon spawning area. The falls and rapids at the outlet from the lake limit the upstream migration of the salmon. Therefore, any development upstream from the falls would not significantly impact the spawning habitat downstream. It should also be noted that because the proposed project would operate on a run-of-the-river basis, there would be no change to either the volume or naturally occurring fluctuations of the river flow below the falls. Refer to Section 6.0 and Appendix B for a description of overall environmental impacts of small hydroelectric developments.

5.4 WAVE

Measurements conducted by the National Research Council in 1974[9] off Tofino indicated that the average power of waves in that area is about 35 kW/m of wave front. It is expected that wave power in the open ocean near Bamfield is also about 35 kW/m. Although there are many wave power technologies being developed in different countries, these technologies have not reached commercial status.[10] Two concepts, the dam-atoll[11] and the oscillating water column[12] appear to be promising. Large structures in the open ocean, 1 to 2 km off the coast, are envisaged in either technology in order to maximize energy capture. Some aspects of the wave power technology such as mooring of the large structures, power transmission to shore, reliability of the device in the marine environment, repair and maintenance in rough seas, and environmental and navigational impacts appear to impede the development and commercialization of these technologies (Appendix A).

Any attempts to make a wave power scheme stand alone would require substantial storage capability because waves are not a constant source of energy. A wave power scheme at Bamfield could conceivably be applied in a diesel fuel saving mode if it is economical to do so. Such a scheme would involve large structures (dam-atoll or oscillating water column) 1 to 2 km from Cape Beale in the open ocean. A distribution line (25 kV), 10 to 12 km long and including 1 to 2 km of submarine cable would be required to interconnect the diesel plant with the wave power plant. This line would have to traverse the Pacific Rim National Park.

No realistic cost estimate for wave power can be made as there are no commercially available wave power schemes. It is optimistically estimated that energy from waves will cost approximately 10¢/kW·h once the technology is fully developed.[12] Thus, some day in the future wave power could be a viable supplement to diesel generated power.

Naturally occurring caverns open to the sea are found to produce compression of air due to wave action. This is a variation of the oscillating water column concept. Power could be extracted from such caverns with air turbines. Generally, the compressive action in natural caverns does not occur for more than a few hours per day. Thus, such a scheme would require considerable energy storage if it was to stand alone. Energy storage as compressed air is possible, but it would require large vessels because of the low pressures involved. Power from natural caverns may have some application in a fuel saving mode at a suitable site. Two natural caverns have been identified in the Bamfield area; there is a cavern measuring approximately 10 m x 20 m x 2 m at Mr. F. Welland's property and there is seemingly a larger cave near Brady's Beach. More data such as air flow and air pressure versus duration of occurrence would be required in order to make a realistic estimate of the energy potential and cost of these natural caves.

5.5 TIDAL

(a) General

The Bamfield area has a limited resource potential for tidal power development. Tidal currents in the waters off Bamfield are uniformly weak (e.g., less than 1 m/s); therefore, free-stream tidal development is not practical.

Some small inlets exist along the coastline near Bamfield, and these could be considered for barrage-type development. However, the relatively low tidal range in the Bamfield area represents a major technical constraint to such developments. The mean tidal range at Bamfield is 2.65 m, which is less than the average experienced on the B.C. coast (Fig. AA4-2 in Appendix A), and it is much less than the tidal range in areas where tidal development is being considered (e.g. the mean tidal range in the Bay of Fundy is 10 to 12 m).

(b) Potential Tidal Sites

A review of maps and marine charts for the Bamfield area indicates there are three potential sites which could be considered for barrage development. The locations of these sites are shown on Fig. A.5-6 and the principal technical data are summarized in Table A5-1.

A preliminary cost index for each site has been determined according to the procedure outlined in Appendix A and the results are presented in Table A5-2. Energy output and pertinent environmental characteristics for each site are described below.

(i) Poett Nook

Poett Nook is a small inlet located about 10 km northeast of Bamfield. The basin could be developed for tidal generation by the construction of a short barrage across the narrow entrance to the inlet. The site has a development potential of about 0.6 GW·h/a which is equivalent to 13 percent of the projected load demand in Bamfield for the 1990/91 fiscal year.

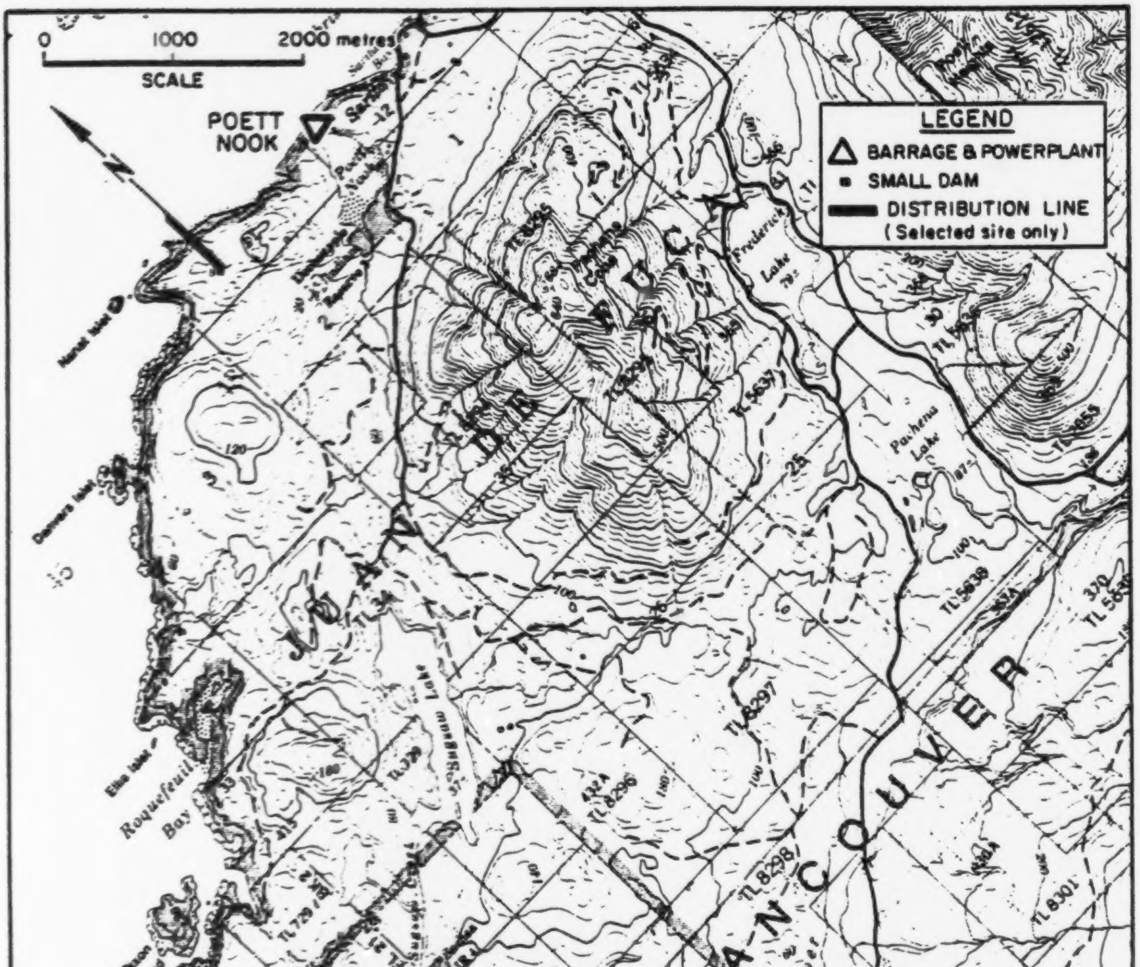
Various non-technical constraints to the implementation of a barrage development at this site have been identified. The main concern would be interference with navigation in and out of the inlet. Poett Nook provides excellent sheltered anchorage for pleasure boats and contains a small marina and campground. The barrage would also disrupt water access to the Indian Reserve located at the south end of the inlet. A small creek draining into the south end of the inlet appears to support some salmon runs and access for these fish could be affected by a barrage development. None of the above constraints appears to be overriding, but mitigation costs could be high (e.g. navigation lock and fishway).

Poett Nook has the further disadvantage of being the most distant of the three potential sites from Bamfield.

(ii) Grappler Inlet

Grappler Inlet is about 1 km northeast of Bamfield. The inlet could be developed by construction of a barrage across the long, narrow entrance to the inlet. The energy capability would be about 1.2 GW·h/a (i.e. about 26 percent of the projected 1990/91 load demand for Bamfield).

Grappler Inlet contains several boat docks and there are at least 20 residences and other buildings along the shore. All of these buildings appear to require water access. There is a large dock on the south side of the inlet (Port Désiré) which provides moorage for commercial fishing boats. These


0
1000
2000 metres
SCALE
N
POETT NOOK
LEGEND
△ BARRAGE & POWERPLANT
▪ SMALL DAM
▬ DISTRIBUTION LINE (Selected site only)
JUAN DE FUCA
VANCOUVER
Frederick Lake
Pachena Lake
Roquefeuil Bay
River
Grappler Inlet
GRAPPLER INLET
Bamfield
12kV, 0.5km
SMALL DAM
BAMFIELD INLET
500kW
Pachena
TREVOR

B.C.HYDRO

BAMFIELD AREA
LOCATION MAP FOR
POTENTIAL TIDAL SITES
FIGURE A.5-6

TABLE A5-1

BAMFIELD - POTENTIAL TIDAL SITES
TECHNICAL DATA

	Tidal Range			Channel Dimensions at Barrage Site		
Site	Mean (m)	Extreme (m)	Basin Area (km²)	Length (km)	Mean Depth (m)	Transmission Distance (km)
1. Poett Nook	2.65	4.1	0.25	0.06	7	10
2. Grappler Inlet	2.65	4.1	0.44	0.08	10	1.0
3. Bamfield Inlet	2.65	4.1	0.52	0.20	4	0.5

TABLE A5-2

BAMFIELD - POTENTIAL TIDAL SITES
CALCULATED PARAMETERS

Site	Annual Energy Potential (GW·h/a)	Barrage Dimensions Length (km)	Barrage Dimensions Mean Height (m)	At-Site Energy Cost Parameter (km - m^2/GW·h)
1. Poett Nook	0.7	0.06	13	14
2. Grappler Inlet	1.2	0.08	16	17
3. Bamfield Inlet	1.4	0.20	10	14

Notes:

1. Annual energy potential is calculated from the formula: E = 0.39 x A x R^2 (GW·h/a) where: A = basin area at mean tide (km^2), R = mean tidal range (m), (Appendix A).

2. Barrage mean height is determined from the sum: (mean depth at low water) + (extreme tidal range) + (freeboard allowance of 2.0 m).

3. At-site energy cost parameter is calculated from the formula: C = L x H^2/E (m^3/GW·h) where: L = barrage length (km), H = barrage mean height (m), E = annual energy potential (GW·h), (Appendix A).

observations indicate that navigation would likely represent a major constraint to a barrage development. In addition, water access to an Indian Reserve at the head of the inlet and fish migration to spawning habitat in the lower reaches of Sugsaw Creek could be affected by a barrage.

(iii) Bamfield Inlet

Bamfield Inlet is the body of water which divides the community of Bamfield. The southwest end of the inlet is a relatively shallow basin which could be developed for tidal generation by the construction of a barrage across the channels between Burlo and Rance islands. The energy capability of this site would be approximately 1.4 GW·h/a (i.e. approximately 30 percent of the projected 1990/91 load demand for Bamfield).

At present navigation does not appear to be a significant concern for the upper reaches of Bamfield Inlet. There are no major commercial moorage facilities, but there are a few private docks associated with residences. Water access to an Indian reserve at the head of Bamfield Inlet would be affected by a barrage, but there appears to be alternative water access on the northern side of the reserve. Fish migration into the upper portion of Bamfield Inlet does not appear to be a significant concern due to the absence of suitable spawning habitat (i.e. only one small creek drains into the upper part of Bamfield Inlet).

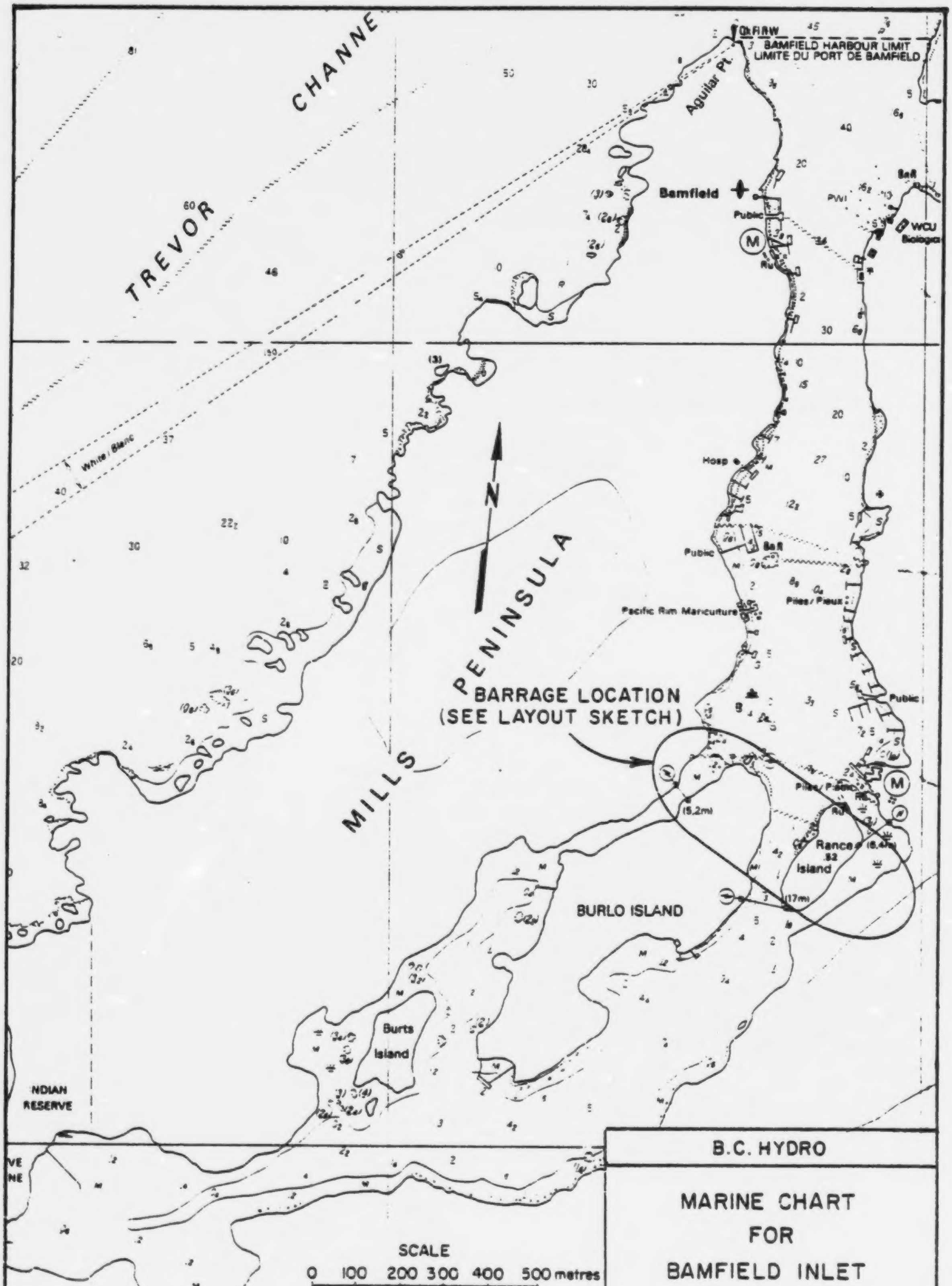
(c) Preferred Site

The above discussion indicates that none of the identified sites appears particularly attractive for tidal development. However, of the three sites, Bamfield Inlet (Fig. A.5-7) would appear to have the best development potential. Thus, this site was selected for developing a conceptual layout in order to assess the cost of tidal generation relative to other options.

(d) Conceptual Layout

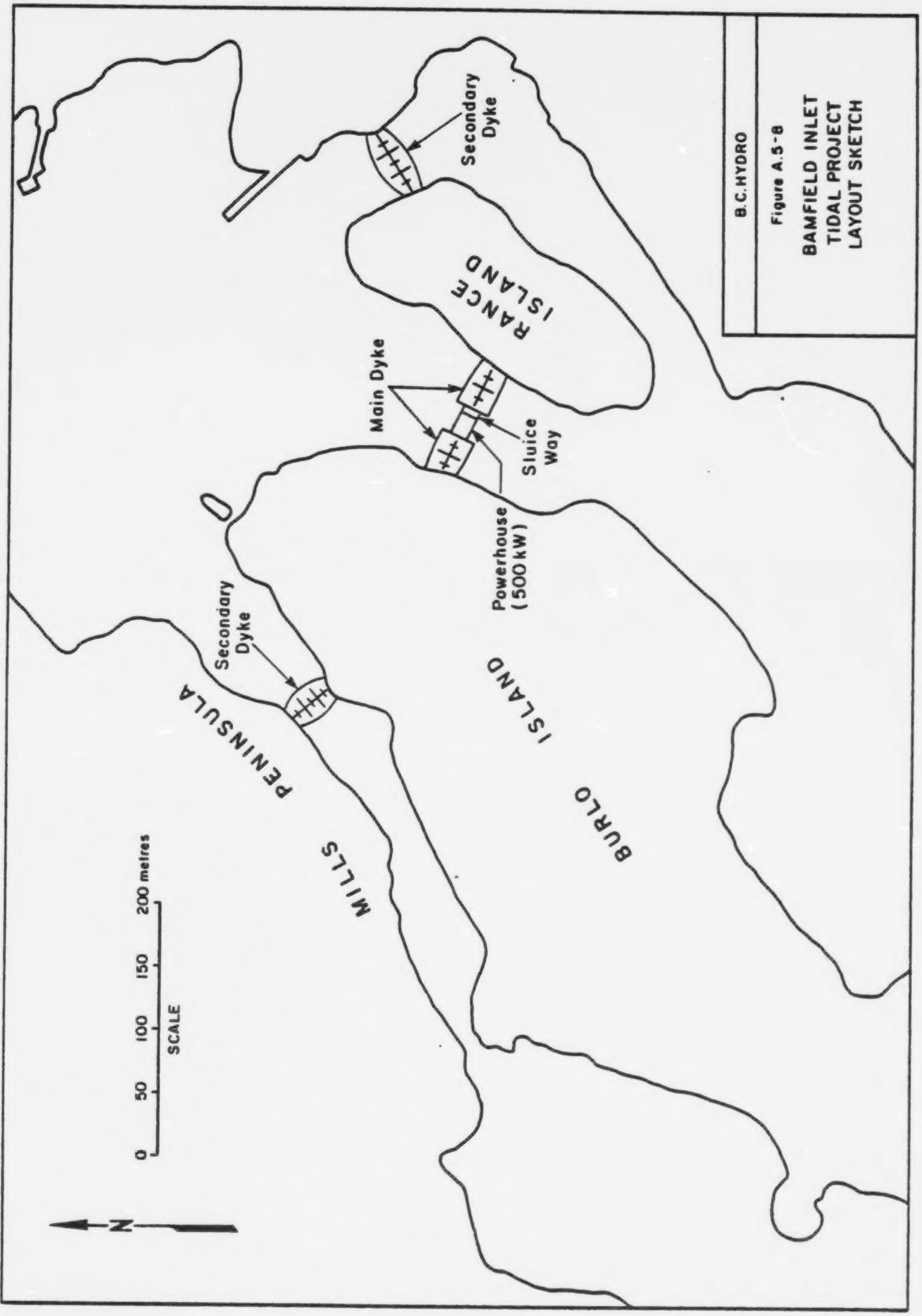
A tidal scheme at Bamfield Inlet would consist of secondary and main dykes in the channels adjacent to Rance and Burlo islands (Fig. A.5-8). The main dyke would incorporate the powerhouse and a gated sluiceway.

The principal design parameters for the project features are listed in Table A5-3. The installed capacity of 500 kW is based on the assumption that the plant would operate at an annual capacity factor of about 30 percent (Appendix A).


TREVOR CHANNE
BAMFIELD HARBOUR LIMIT
LIMITE DU PORT DE BAMFIELD
Aguilar Pt.
Bamfield
Public
WCU Biologica
Hosp
N
White / Blanc
MILLS PENINSULA
Pacific Rim Mariculture
Piles / Pieux
BARRAGE LOCATION
(SEE LAYOUT SKETCH)
(5.2m)
(17m)
(6.4m)
Rance Island
BURLO ISLAND
Burts Island
NDIAN RESERVE
SCALE
0 100 200 300 400 500 metres
DEPTHS IN METRES

B.C. HYDRO

MARINE CHART
FOR
BAMFIELD INLET
FIGURE A.5-7


Secondary Dyke
RANCE ISLAND
Main Dyke
Sluice Way
Powerhouse (500 kW)
Secondary Dyke
BURLO ISLAND
MILLS PENINSULA
SCALE
0
50
100
150
200 metres
N

B.C. HYDRO

Figure A.5-8

BAMFIELD INLET TIDAL PROJECT LAYOUT SKETCH

TABLE A5-3

BAMFIELD INLET TIDAL PROJECT PRINCIPAL DESIGN PARAMETERS

Installed capacity	500 kW
Annual energy	1.4 GW·h/a
Powerhouse data	
- number of units	1
- turbine-generator type	tubular
- rated head	2.5 m
- rotor diameter	2.75 m
- floor area	150 m^2
Sluiceway discharge area	12 m^2
Dyke volume	
- main dyke	25 000 m^3
- secondary dykes	7 500 m^3
Distribution line length	0.5 km

The dykes are assumed to be constructed of dumped rockfill with an impervious till core to prevent seepage. The powerhouse and sluiceway structures would be constructed as caissons which could be floated into position and sunk onto a prepared foundation.

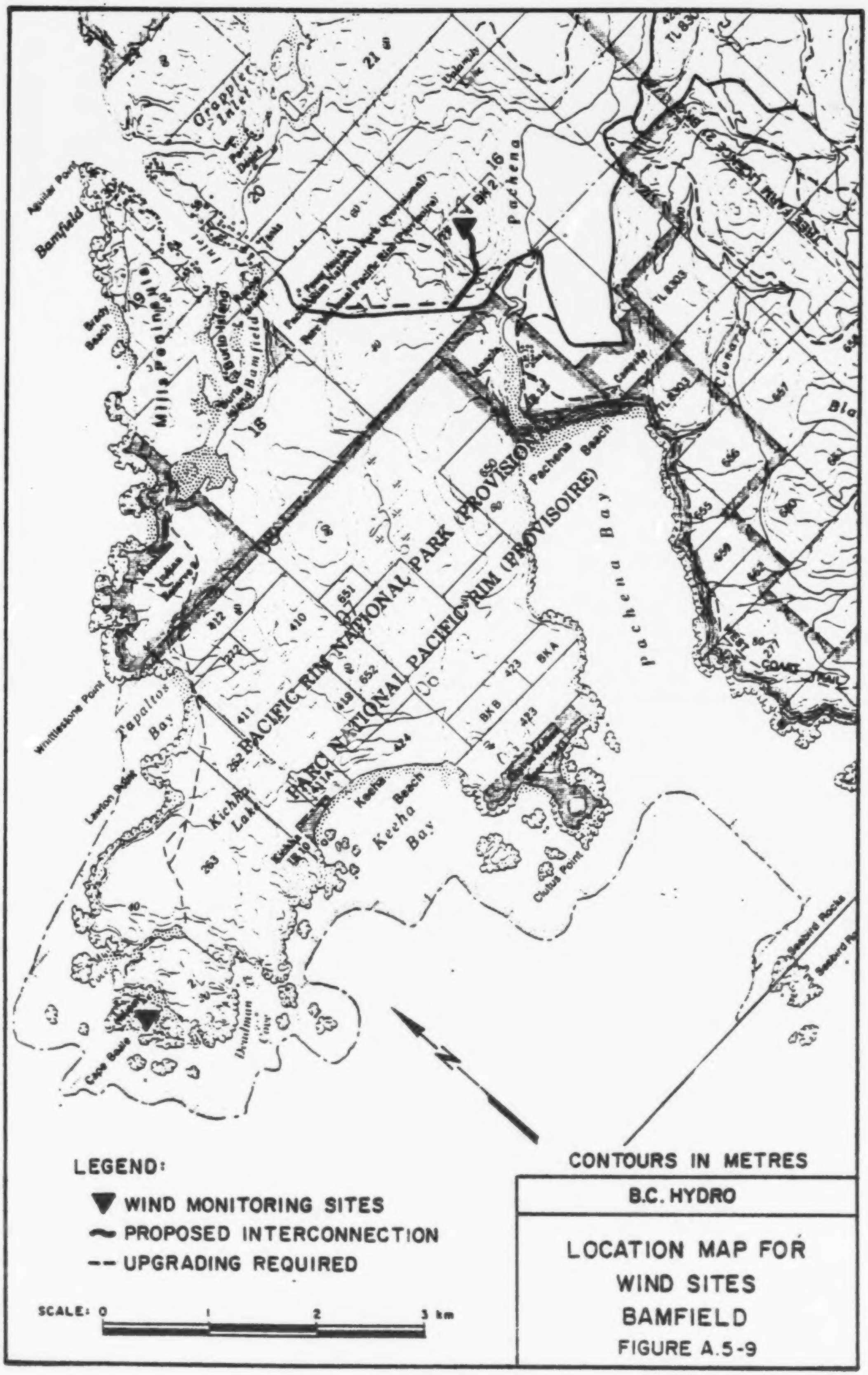
5.6 WIND

Electrical energy production from wind is one of the renewable energy options that merit consideration at Bamfield. Power from wind could be considered only as a supplementary source because of the unpredictability and variability of wind. Thus wind generators could be installed to reduce the diesel fuel consumption at the existing powerhouse. The amount of fuel that could be saved would depend on the wind regime and the installed capacity of the wind machines.[14] The optimum capacity of the allowable wind component is about equal to the minimum demand of the system and with a favorable wind regime such an installation could save as much as 25 percent of the fuel.

Wind data collected by the Atmospheric Environment Service at Cape Beale Light (1969 to 1975)[15] indicate an average wind speed of about 4.8 m/s (17.3 km/h). A wind monitoring site on a 100 m hill about 2 km from Bamfield was jointly established by the National Research Council and B.C. Hydro in December 1981 (Fig. A.5-9). The data from this site, though not continuous, gives an average wind speed of about 4.5 m/s for 1982/83 which is about the same as the AES average at Cape Beale. The data obtained from the Bamfield measurements are being analyzed by TES Ltd., in Ottawa. They have computed the maximum extractable wind energy (Betz Limit) and the energy which could be extracted by a 50 kW vertical axis wind turbine (VAWT) made by DAF Indal of Mississauga, Ontario. Analysis of 1 year of data from Bamfield indicates that the VAWT could utilize about 21 percent of the theoretical maximum extractable wind energy. This would give a capacity factor of 6 percent for a 50 kW VAWT at Bamfield.

Based on a capacity factor of 6 percent, a cost estimate shows that energy could be produced by a VAWT at Bamfield for 65¢/kW·h (1983$). Literature research indicates that a well-designed horizontal axis wind turbine with pitch control may be able to utilize as much as 50 to 60 percent of the extractable energy,[14] but the installation would be more expensive. It is expected that the energy cost could not be reduced to less than 50 percent of the cost of energy from a 50 kW VAWT.

By 1990/91 Bamfield is expected to have a peak demand of approximately 980 kW. Typically, the minimum load in such areas is about 35 percent of the peak, which is equivalent to 340 kW for Bamfield. If we assume that the maximum wind generating capacity is about the same as the minimum load, a usable wind generating capacity of 300 kW is estimated. An installation consisting of six 50 kW VAWTS could contribute about 157.7 MW·h in 1990. This is approximately 3.4 percent of the 4.65 GW·h load expected by that date.


Grappler Inlet
Aguilar Point
Bamfield
Mills Peninsula
Brady Beach
Bamfield Inlet
Pachena
Pachena Beach
Pachena Bay
PACIFIC RIM NATIONAL PARK (PROVISIONAL)
PARC NATIONAL PACIFIC RIM (PROVISOIRE)
Whittlestone Point
Tapaltos Bay
Kichha Lake
Keeha Beach
Keeha Bay
Clutus Point
Cape Beale
Seabird Rocks
WEST COAST TRAIL
N

CONTOURS IN METRES

LEGEND:

- ▼ WIND MONITORING SITES
- ~ PROPOSED INTERCONNECTION
- -- UPGRADING REQUIRED

SCALE: 0 1 2 3 km

B.C. HYDRO

LOCATION MAP FOR WIND SITES BAMFIELD

FIGURE A.5-9

The principal environmental impact of wind generation at Bamfield is land alienation. Assuming a rotor width of 11.2 m, an allowance of 10 rotor widths/turbine and an added allowance for clearing around the turbines, approximately 9 ha would be required for a 300 kW windfarm consisting of six 50 kW units.

5.7 THERMAL

(a) Fuel Supply

(i) Introduction

Potential fuel supplies for a thermal plant at Roquefeuil Bay are wood waste, wood from tree farms, municipal solid waste, peat and coal. These fuels could be used to produce steam or gas.

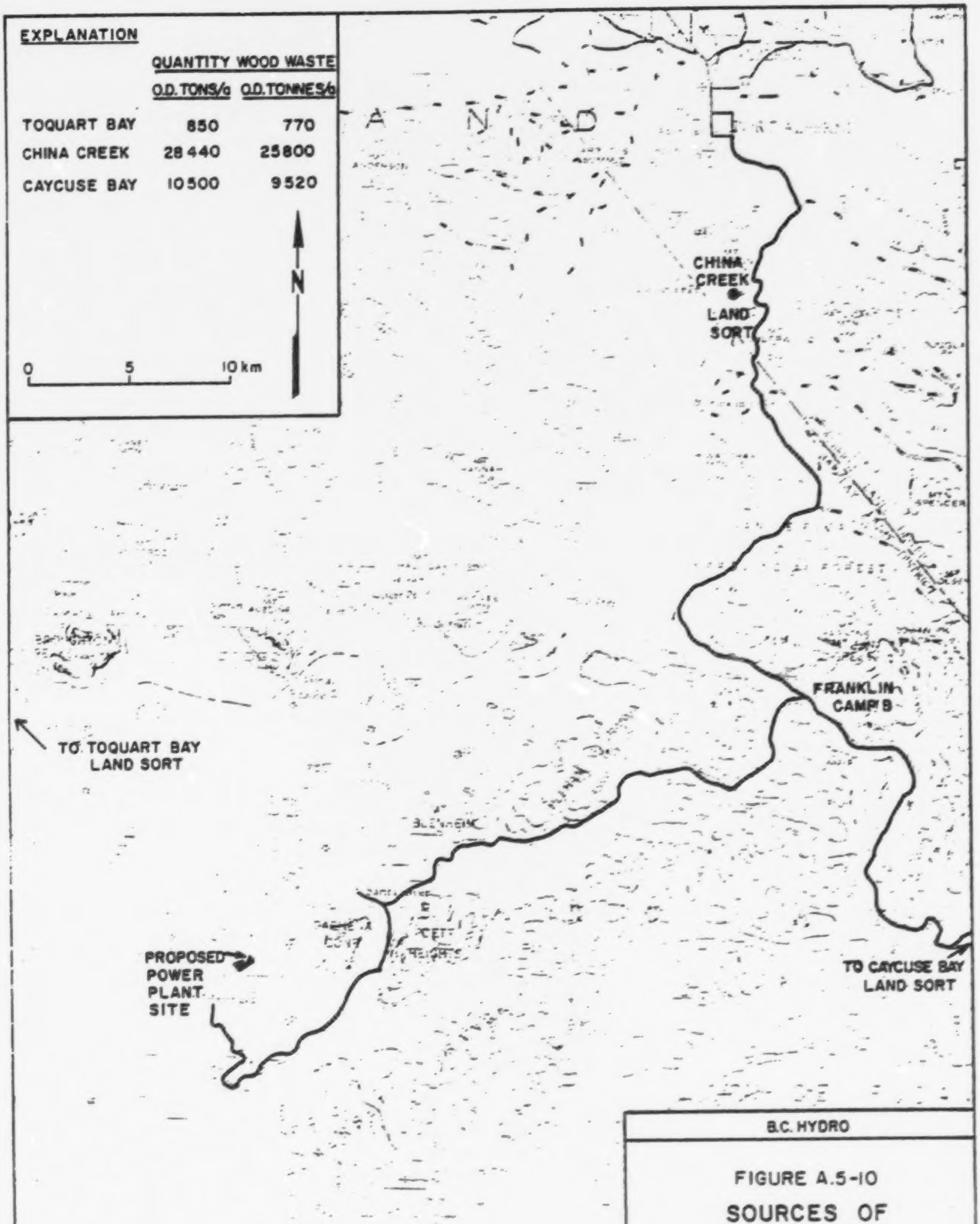
(ii) Biomass

A. Wood Waste

It is estimated that between 4600 and 5900 ODtonnes of wood waste would be required per annum in order to generate 4.65 kW·h/a (net) for Bamfield. The smaller quantity would be required for direct firing in a steam boiler and the larger quantity would be required for gasification.

There are logging operations along both sides of Imperial Eagle Channel and Alberni Inlet (Fig. A.5-10). The principal operator is MacMillan Bloedel Limited. B.C. Forest Products Limited and Coulson Prescott Logging Limited also have logging operations in this area. Most of the logs from these operations are brought to three dry land sorts and three log dumps.

MacMillan Bloedel is the largest holder of timber rights in the area. In addition they also have pulp mill, plywood and sawmill operations at Port Alberni. Wood waste produced at Port Alberni is used by the pulp mill for producing process steam and electricity. Most of the logs collected adjacent to the Alberni Inlet by MacMillan Bloedel are taken to one of three dumps and are handled through the China Creek land sort. The dumps are located at the mouths of the Sarita River and Coleman and Spencer creeks. It may be feasible to haul wood waste to these sites for barge loading. However, space at these sites is very limited and the terrain is steep; there may be insufficient space for a suitable barge landing. The Spencer Creek dump is pictured in Fig. A.5-11. The



EXPLANATION

	QUANTITY WOOD WASTE	
	O.D. TONS/a	O.D. TONNES/a
TOQUART BAY	850	770
CHINA CREEK	28 440	25800
CAYCUSE BAY	10 500	9520

N
0
5
10 km
CHINA CREEK LAND SORT
FRANKLIN CAMP B
TO TOQUART BAY LAND SORT
TO CAYCUSE BAY LAND SORT
PROPOSED POWER PLANT SITE

B.C. HYDRO

FIGURE A.5-10
SOURCES OF WOOD WASTE BAMFIELD

FIGURE A.5-11 View of the Spencer Dump

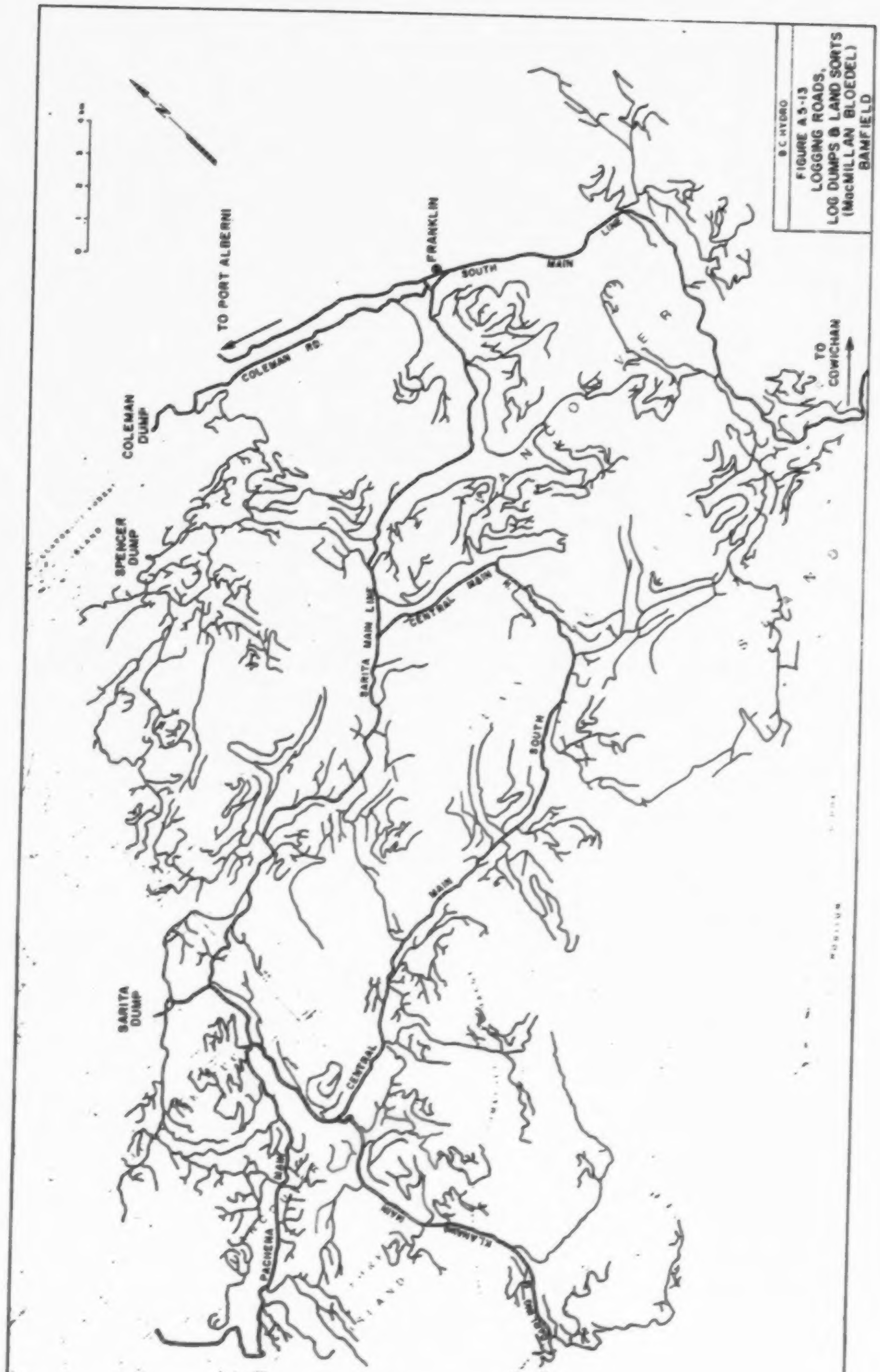
FIGURE A.5-12 View of the Sarita Land Sort (This land sort is now used only as a log dump)

distance from the Spencer Creek dump to Bamfield is 22 km. Both the Sarita dump and the China Creek dry land sort are paved. The Sarita dry land sort, which is within 10 km of Bamfield, was recently converted to a log dump, due to decreased logging activity in the area and the concentrating of log sort activity at China Creek (Fig. A.5-12).

The China Creek dry land sort is on tidewater and is 42 km by barge from Bamfield. Approximately 1 500 000 m^3 of good logs can be handled through the China Creek land sort each year (C.J. Burrell, MacMillan Bloedel, personal communication). MacMillan Bloedel has been operating recently at 60 to 70 percent capacity and producing approximately 50 000 m^3 (20 000 OD tonnes) of wood waste annually at China Creek. The wood waste is presently burned or buried near the China Creek sort yard. MacMillan Bloedel have estimated that it is not economical to install facilities to process the wood waste and take it to Port Alberni where there is reportedly a shortage of hog fuel.

It is estimated that approximately 108 000 m^3/a (43 200 OD tonnes/a) of wood waste would be left at landings and roadsides during logging (Al Dent, MacMillan Bloedel, personal communication). The MacMillan Bloedel road network for the Bamfield area is illustrated in Fig. A.5-13. Logging slash and other wood waste at landings is presently burned after logging. As well as utilizing the wood waste, clearing of landings would result in the salvage of some good logs which could be used to offset the cost of collecting the wood waste for fuel.

B.C. Forest Products Limited has a paved dry land sort, near Caycuse on Cowichan Lake. An annual volume of 465 000 m^3 of logs are handled through the Caycuse land sort.[16] This operation produces 23 250 m^3 (9 300 OD-tonnes) of wood waste. The wood waste consists of cull logs, broken and butt ends, split logs, bark and branches which have the following species mix: 54 percent hemlock, 26 percent Douglas fir, 9 percent balsam fir, 9 percent cedar, and 2 percent other species. The wood waste at the dry land sort is presently being incinerated on site. Forest slash and other logging debris is also available at the 100 to 150 landings scattered throughout the logging area. Because the B.C. Forest Products logging operation is centred around the Caycuse land sort which is 95 km from the Roquefeuil Bay site near Bamfield, only the readily available wood waste at the



B C HYDRO

FIGURE A5-13
LOGGING ROADS,
LOG DUMPS & LAND SORTS
(MacMILLAN BLOEDEL)
BAMFIELD

N
TO PORT ALBERNI
FRANKLIN
COLEMAN DUMP
COLEMAN RD.
SOUTH MAIN LINE
SPENCER DUMP
SARITA MAIN LINE
CENTRAL MAIN
SOUTH MAIN
SARITA DUMP
CENTRAL
PACHENA MAIN
KLANAWA MAIN
TO COWICHAN

land sort could possibly provide an economical fuel for the proposed thermal station.

Coulson Prescott Logging Limited has a gravel-surfaced dry land sort on the west shore of Toquart Bay. Approximately 54 000 m^3 of logs are handled through the Toquart Bay land sort each year and approximately 2200 m^3 (880 OD tonnes) of wood waste are buried on-site.[17] It is estimated that approximately 3780 m^3 of forest residues are left at landings and in the bush. The forest residues are burned after logging in order to facilitate replanting.

Wood waste from the China Creek and other land sorts along the Alberni Inlet could provide a good reliable source of fuel for a thermal generating station. A total of 50 880 m^3 (26 300 ODtonnes) of wood waste could be supplied from these locations, but it is not expected to be the most economical source of wood fuel. Approximately 43 200 ODtonnes/a of wood waste could be available from freshly logged areas in the Bamfield area (within 32 km of the station). Discussions with MacMillan Bloedel and the Forest Engineering Research Institute of Canada (FERIC) have indicated that the daily production of forest residues from only two or three landings could supply the daily fuel requirement for the thermal generating station. The Caycuse dry land sort on Cowichan Lake could provide additional wood waste, but it is unlikely to be an economical source of fuel for a proposed plant site at Roquefeuil Bay. The locations of the dry land sorts are illustrated in Fig. A.5-10.

It may be possible to recover wood waste more efficiently by yarding and hauling logging slash and unmerchantable timber to a central hogging site at a barge landing or at the plant site. Another concept would envisage a portable hogger being brought into a landing, producing and stockpiling the hog fuel, then moving on to the next landing. A front end loader and chip trucks could collect the hog fuel and move it to the plant site when sufficient hog fuel was produced in one area. This would result in more effective utilization of the hogger.

B. Tree Farms

A tree farm could be established near the generating station to provide a reliable source of wood fuel. A more detailed description of tree farm fuel supply is contained in Appendix A. Red alder (Alnus rubra) is a fast-growing, indigenous tree which could be utilized in tree farm operations. In the favourable West Coast climate approximately 4.24 ODtonnes of wood fuel could be produced annually per hectare (Table AA7-5, Appendix A).[18] This yield is based on a dense stand of alder planted on a medium quality growing site and grown without fertilization or supplementary irrigation.

The terrain near Bamfield is steep, but it is assumed that an area of 1300 ha (13 km²) of relatively flat land could be found. No specific site for a tree farm has been selected, but for this study it is assumed to be an average distance of 9.0 km from the proposed plant site. However, all of the suitable land is already under some form of tenure; most of the land lies within tree farm licences. If a suitable site could be found, the existing trees on the site could be harvested and, depending on the site, could be supplemented with available wood waste until the first crop of wood could be harvested from a tree farm.

C. Peat

A study of peat resources in coastal British Columbia is being conducted by Agriculture Canada. No sources of peat have been identified near Bamfield, although there are numerous sites north of Tofino, on Vargas and Flores islands and on Vancouver Island near Hesquiat. The closest of these sites is approximately 85 km northwest of Bamfield and part of this distance would be on the exposed outer coast which would make transportation difficult and expensive. The high moisture content (approximately 90 percent moisture) and low heating value (approximately 2.3 MJ/kg) of in situ peat make it necessary to dry the peat before shipping, which further increases the fuel cost. The low heating value of even partly-dried peat (10 MJ/kg at 50 percent moisture) requires that the source of peat be close to the thermal plant. Therefore, for these reasons and because there are other alternatives, it is unlikely that peat could be economically shipped from a source elsewhere along the coast to a thermal plant at Bamfield. Refer to Appendix A for a description of peat technology.

(iii) Coal

There are no local sources of thermal coal near Bamfield, although there are sources elsewhere on Vancouver Island. Coal deposits and occurrences have been found in the Nanaimo, Comox, Quinsam and Suquash areas on the east side of Vancouver Island, near Port Alberni in central Vancouver Island and at Standby River, Winter Harbor, Quatsino, Coal Harbour, Esperanza Inlet, Nootka, Estevan Point, Flores Island, Clo-oose, River Jordan and Sooke on the north and west coasts of Vancouver Island. Reserves of coal have been outlined in the Nanaimo, Comox and Quinsam areas and of these reserves only those at Quinsam are likely to be mined in the foreseeable future.

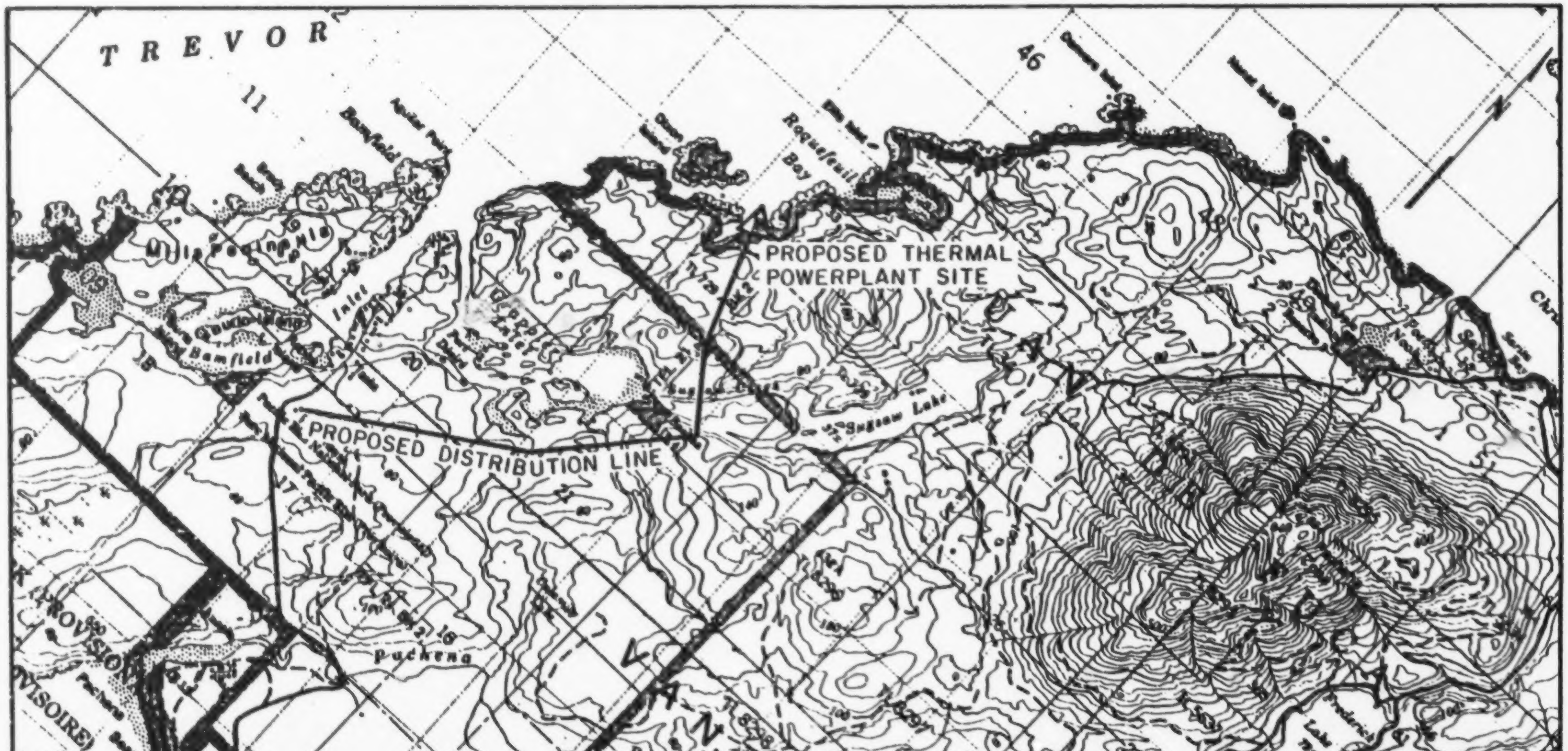
Recent decreases in the demand for thermal coal and a drop in price of 22 percent for coal from Byron Creek Collieries Limited (Vancouver Province, 12 October 1983) in the East Kootenays would make it unlikely that the Quinsam mine would open soon. It is assumed that other thermal coals have suffered price reductions similar to those suffered by thermal coal from Byron Creek. Most East Kootenay coals are shipped from Roberts Bank near Vancouver which is closer to Bamfield than Middle Bay (north of Campbell River) which is the proposed port for shipping Quinsam coal. Therefore, East Kootenay coal is selected as the possible source of fuel for a coal-fired thermal plant at Bamfield. The quality (as shipped) of thermal coal from Westar Limited (formerly B.C. Coal) is as follows: 10.0 percent moisture, 16.2 percent ash, 21.5 percent volatile matter, 56.0 percent fixed carbon, 0.4 percent sulphur and a gross heating value of 25 750 MJ/kg.[19] Approximately 2230 t/a of coal would be required for a coal-fired thermal plant. The coal is delivered to Roberts Bank by CP Rail where it could then be loaded on a barge and delivered to Bamfield.

(b) Generating Station Design

(i) Conventional Thermal

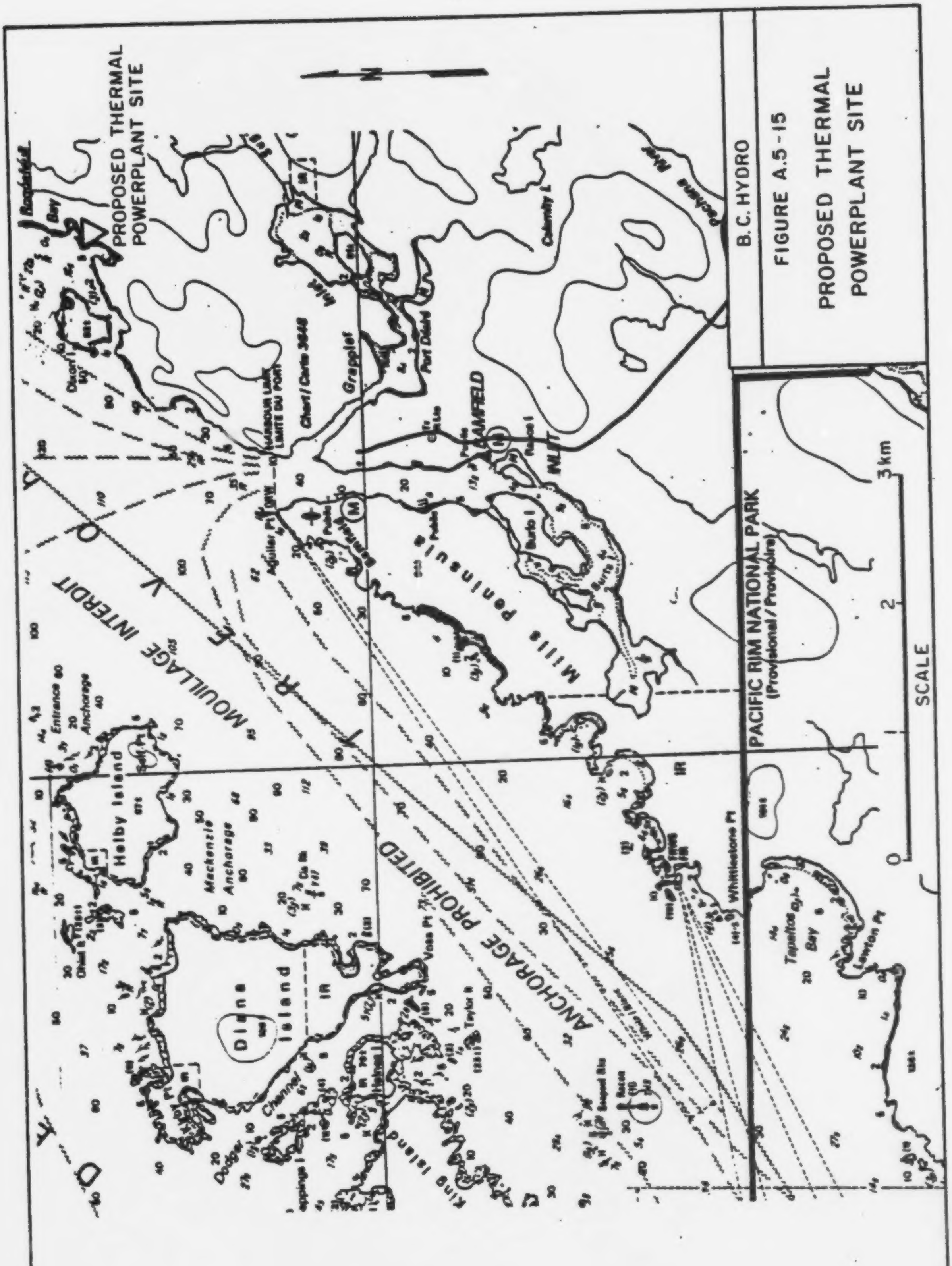
The total generation and peak requirements of Bamfield could be met with a small thermal generating plant fired by biomass (including wood waste, wood from tree farms, municipal solid waste or peat) or coal with the resulting steam driving a single 1000 kW turbine/generator set. This plant could provide the required 4.65 GW·h/a at a 53 percent capacity factor. The two 500 kW portable diesel units could be moved to the new plant site for use as standby and emergency power. They would also give the steam plant "black start" capability. For estimating purposes a location near Roquefeuil Bay, northeast of Bamfield, has been assumed as the plant site (Figs A.5-14, A.5-15). An area of approximately 2 ha would be required for the generating station.

It is proposed that the powerplant equipment be purchased as "packaged units" matched to each other, in order to simplify on-site assembly. The major equipment items for a 1 MW (net) power package could be supplied as follows:[20]


TREVOR
11
46
Bamfield
Inlet
Roquefeuil
Bay
PROPOSED THERMAL
POWERPLANT SITE
PROPOSED DISTRIBUTION LINE
Sugsaw Lake
Pachena
Pachena Beach
Bay
River
VANCOUVER
Black
0
1
2
3
4km
SCALE

B.C. HYDRO

FIGURE A.5 - 14
PROPOSED THERMAL
POWERPLANT SITE
WITH TRANSMISSION


PROPOSED THERMAL POWERPLANT SITE
N
Bay
Diana Island
IR
Helby Island
Mackenzie Anchorage
Entrance Anchorage
MOUILLAGE INTERDIT
ANCHORAGE PROHIBITED
Dodger Channel
King Island
Vose Pt
Taylor R
Aguilar Pt
HARBOUR LIMIT
LIMITE DU PORT
Chart / Carte 3646
Grappler
Port Désiré
BAMFIELD INLET
Mills Peninsula
Burlo I
Whittlestone Pt
Tapaltos Bay
Lawton Pt
Calamity L
Pachena River
PACIFIC RIM NATIONAL PARK
(Provisional / Provisoire)
SCALE
0
1
2
3 km

B.C. HYDRO

FIGURE A.5-15

PROPOSED THERMAL POWERPLANT SITE

1. Boiler with a 9072 kg/h (20 000 lb/h) maximum steam capacity at 3100 kPa and 350°C (450 psig at 660°F), suitable for coal or wood-firing, complete with fuel screw feeders and hoppers, de-ashing valves, ID and FD fans, control panel, completely assembled and skid mounted.

2. Turbine/generator, steam turbine, speed 6600/1800 rpm through speed reduction gearing; alternator rated at 1170 kW at 440 V, 3-phase, 60 Hz, 1800 rpm, 0.8 power factor; all mounted on an integral frame incorporating condenser and lube oil tank. Unit power requirements are about 160 kW leaving approximately 1 MW net power output available.

3. A set of interconnecting pipe work for the above equipment.

4. Cyclone separator, bag-house filter and stack suitable for the boiler.

5. Feedwater package including extraction pumps, feedwater heaters and deaerator, boiler feed pumps and control valves.

6. Fuel and ash handling equipment.

7. Packaged water treatment plant for the selected boiler.

8. Suitable steel building to house the above equipment plus administration, operation and maintenance space.

9. All electrical switchyard equipment including transformers, disconnects, circuit breakers, protection devices etc.

10. Circulating water system package including debris screens, pumps and piping to supply up to 7570 L/min of cooling water at a maximum temperature of 27°C.

11. Access roads and site facilities such as fuel barge docking and unloading facilities, fuel storage area, ash disposal area, sanitary facilities and fresh water supply.

(ii) Wood Gasification-Engine Generation

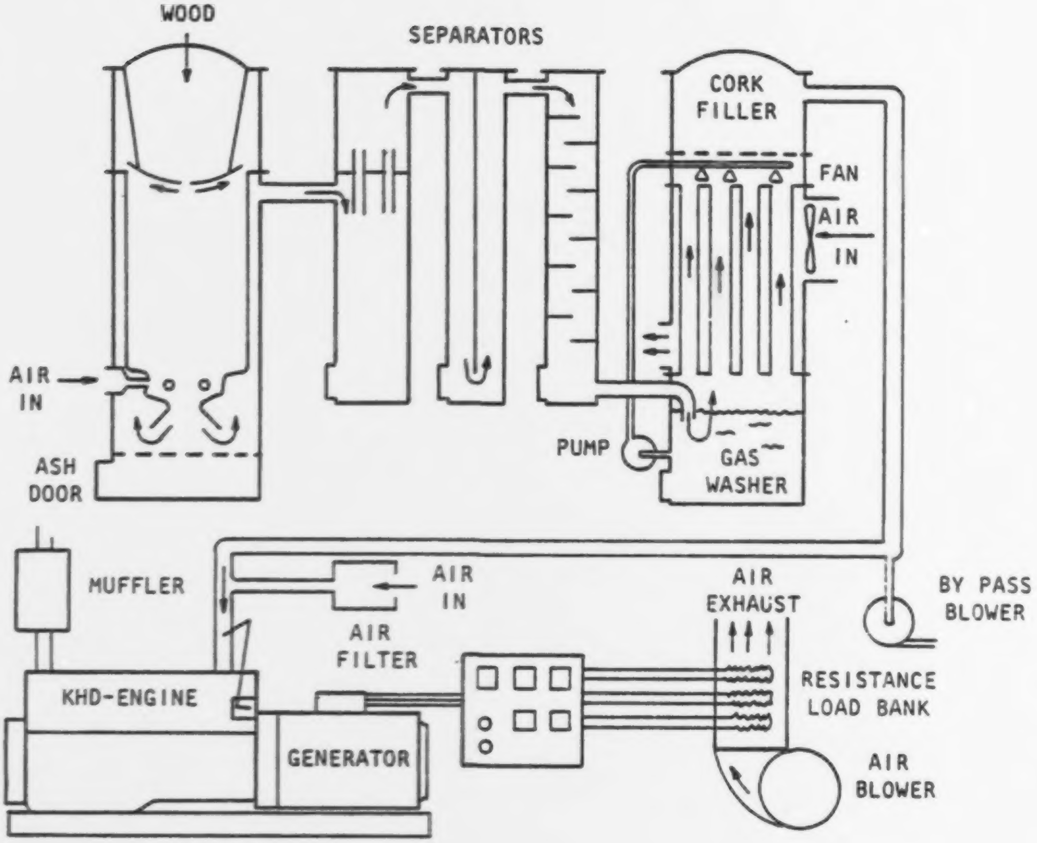
Wood gasification-engine generation is a second thermal power generation option based on processed biomass fuel. As noted in Appendix A of this report, the biomass gasification-engine generation technology is not fully developed. However, an

Imbert gasifier feeding a Duetz (KHD) diesel generating set could provide fairly reliable power (Fig. A.5-16).

In order to provide Bamfield with 4.65 GW·h (net) of power with a peak demand of 980 kW a plant capable of generating 1 MW (net) at a capacity factor of 54 percent would be required. A 600 kW mobile generating unit would be required for peaking and standby service. A 128 kW wood gasification-engine generating system is installed and in operating order at Fort Providence, Northwest Territories (Sieg O. Phillips, Snowshoe Inn, personal communication). A quotation by Imbert for a 512 kW generating system was provided to Mr. Sieg Phillips of Port Providence and used in this report as the basis for the following major equipment selection for the gasifier-engine generating station (Fig. A.5-17):[21]

1. 4 - Feed systems (type 10 000) which would include automatic feeding and exhaust gas drying.
2. 4 - Downdraft wood gasifiers (type 688) producing 172 to 688 m^3/h of low-Btu gas from 80 to 320 kg/h of wood waste.
3. 4 - Dust separators (type 688/6) which would be multicyclones.
4. 4 - Scrubber-type gas coolers (type 688).
5. 4 - Water cooling towers for the gas coolers (type 688).
6. 4 - Electrostatic filters (type 688).
7. 4 - Gas blowers (type 350/500) for plant start-up.
8. Switchboards and control panels.
9. 8 - Suction gas engine generator sets which would be 4-cycle, 1800 rpm, V-12 units with 168 kV·A self-excited alternators (128 kW each).
10. Piping, valves and instrumentation.

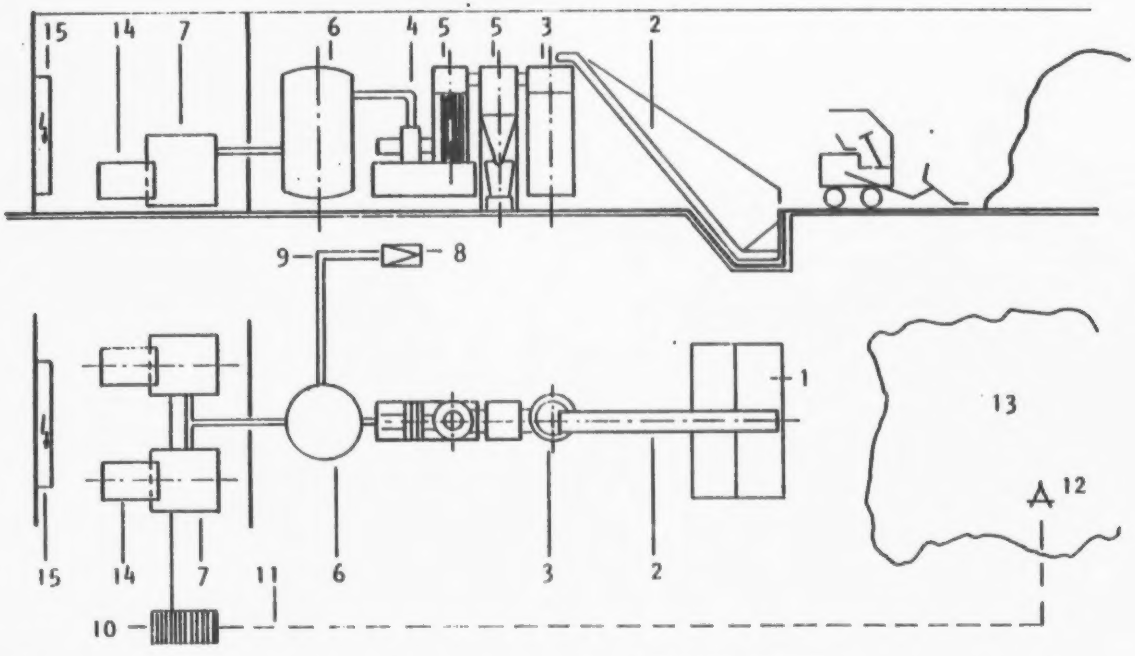
Wood fuel storage, chipping, drying and feeding facilities would be required, as well as off-site facilities including land, buildings, water supply, water treatment, ash disposal, power supply and switchgear similar to that required by a conventional thermal plant. The wood gasification-engine generation process schematic and a typical layout (one-quarter of the plant) are described in Appendix A.


WOOD
SEPARATORS
CORK
FILLER
FAN
AIR
IN
AIR
IN
ASH
DOOR
PUMP
GAS
WASHER
MUFFLER
AIR
IN
AIR
FILTER
AIR
EXHAUST
BY PASS
BLOWER
KHD-ENGINE
GENERATOR
RESISTANCE
LOAD BANK
AIR
BLOWER

B.C.HYDRO

FIGURE A.5-16

IMBERT GASIFIER


15
14
7
6
4
5
5
3
2
9
8
1
13
A 12
15
14
7
11
6
3
2
10

1. FUEL-BUNKER
2. FEEDING INSTALLATION
3. GASIFIER
4. SUCTION BLOWER
5. GAS-COOLING AND CLEANING PLANT
6. GAS-CONTAINER
7. MOTOR
8. HEATING BURNER
9. GAS PIPELINE
10. HEAT EXCHANGER-WATER
11. HEAT EXCHANGER-AIR
12. FUEL DRYING
13. FUEL STOCK
14. ELECTRIC-GENERATOR
15. SWITCH-GEAR

B.C. HYDRO

FIGURE A.5-17
MODULAR POWER PLANT LAYOUT
(120kW to 6,000kW)

The Imbert gasifier requires biomass fuel ranging in size from large chips to fist size lumps. Small quantities of excelsior, saw dust and bark may be included. One kilogram of air-dried wood of no more than 15 to 20 percent moisture by weight would yield approximately 2.3 m^3 of product gas. Therefore, one litre of diesel fuel could be displaced by 3 to 3.5 kg of wood.[21]

An output of 1 kW·h requires 1.0 to 1.4 kg of solid wood fuel (Fig. A.5-18) as described in Appendix A. Fuel feeding and ash removal facilities would be built for continous operation. The Imbert wood gasification plant operates on the principle of a suction-gas plant, i.e. there is always negative pressure in the plant during operation, thus no gas will escape. The vacuum is produced in the motor or by a suction fan. The special design of the Imbert gasifier enables self-regulating quick response of the gasifier to the engine controls.

Since the Imbert gasifier is a down draft gasifier, the gas passing through the red hot charcoal bed is largely reduced to carbon monoxide, thus increasing the percentage of combustible gas. Even at a low load factor the high temperature of the bed would decompose any moisture to hydrogen and oxygen. The pyrolignite, phenols and tar are decomposed, cracked and transformed into easily combustible gases. The only waste remaining is a small innocuous quantity of wood ash.

The analysis of gas from the Imbert gasifier (by volume) is listed in Table A5-4.

The low-Btu gas-fired engines burn the wood gas very cleanly and efficiently. In test installations the exhaust emission levels have been 5 to 10 g/kW·h for carbon monoxide, less than 1.5 g/kW·h for the nitrous oxides, and less than 2.0 g/kW·h for hydrocarbons.

5.8 GEOTHERMAL

Geothermal technology is summarized in Appendix A. Hot or warm springs have been reported at the following locations on the west coast of Vancouver Island (Fig. A.5-19):[22,23]

1. Sharp Point
2. Ahousat
3. Matilda Inlet
4. Mate Island
5. Fair Harbour
6. West of Flores Island
7. Hesquiat Harbor

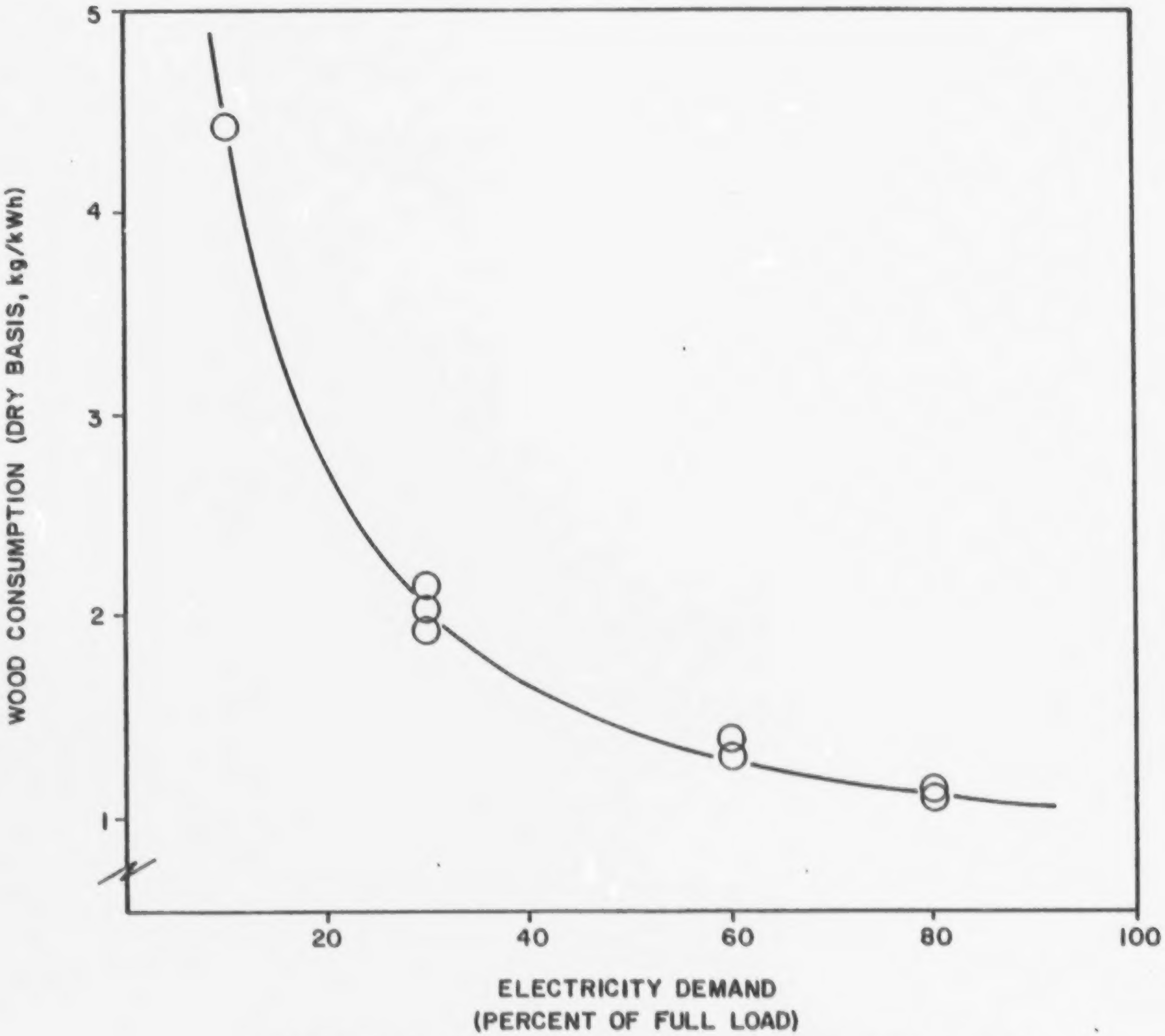
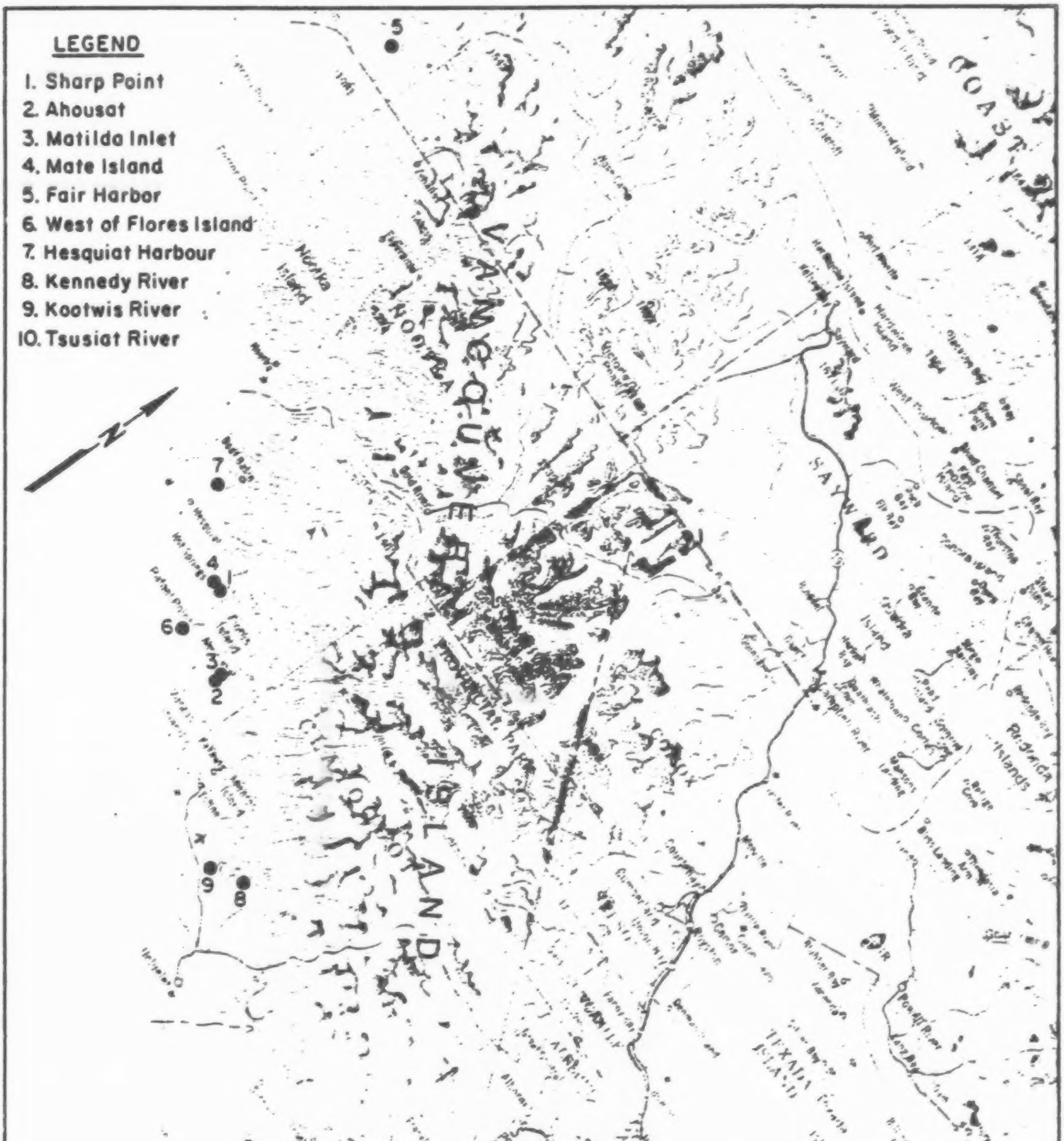


FIGURE A.5-18 WOOD CONSUMPTION vs ELECTRICITY DEMAND

TABLE A5-4

ANALYSIS OF PRODUCT GAS FROM AN IMBERT GASIFIER

Gas	Analysis (%)
CO	23
H_2	15
CH_4	2
CO_2	10
N_2	50


LEGEND
1. Sharp Point
2. Ahousat
3. Matilda Inlet
4. Mate Island
5. Fair Harbor
6. West of Flores Island
7. Hesquiat Harbour
8. Kennedy River
9. Kootwis River
10. Tsusiat River
N
1
2
3
4
5
6
7
8
9
10
0
10
20
30
40
50 km
SCALE

B.C. HYDRO

REPORTED HOT SPRINGS ON VANCOUVER ISLAND

FIGURE A.5-19

8. Kennedy River
9. Kootwis River
10. Tsusiat River

In 1975, examinations of these locations by Nevin Sadlier-Brown Goodbrand Limited for B.C. Hydro consisted of airborne infrared and/or site investigations. No thermal springs were found at Fair Harbor, Kennedy River, Kootowis River or Tsusiat River. Warm water at Hesquiat was believed to be due to solar heating and the warmer water in the ocean off Flores Island as detected by infrared scanning is believed to be caused by warm ocean currents and not by geothermal activity.

The verified geothermal sites on Vancouver Island are at Sharp Point, Ahousat, Matilda Inlet and Mate Island. These sites are approximately 90 km from Bamfield. The geothermal activity is related to two north northwest-trending faults.[24] Movements on these faults are unknown.

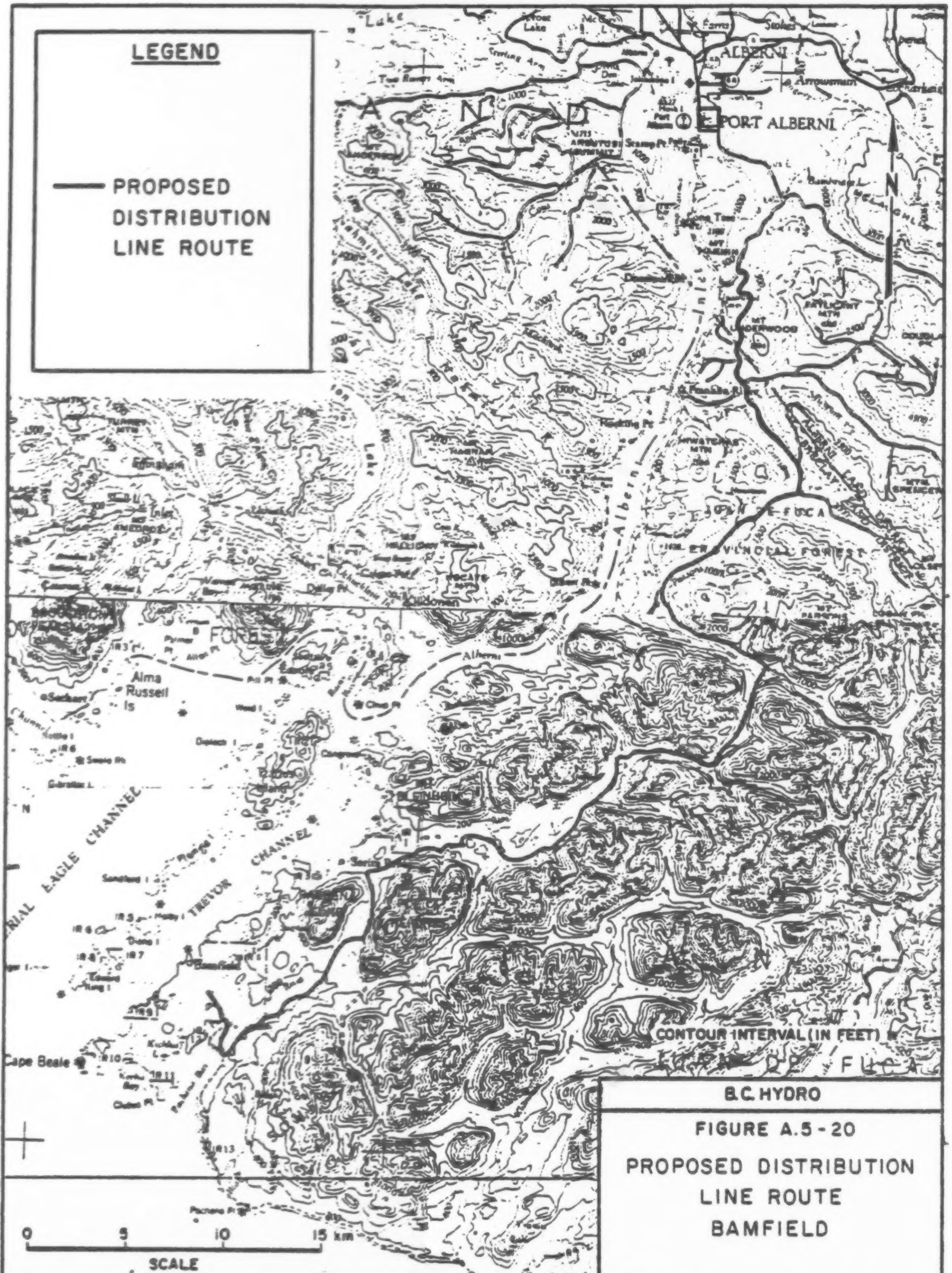
Vancouver Island is geologically unattractive as a site for geothermal power generation. The ocean bottom off Vancouver Island is crossed by an elongate ridge which trends northeast and is offset by northwest and west northwest-trending faults. The resulting ridges form part of the Pacific Rise which is a slowly spreading centre off Vancouver Island. The slow spreading of the sea floor in this area has resulted in its subduction under the continental crust. This slow subduction has caused relatively low heat flow from the crust on the west coast of Vancouver Island.

It is concluded that there are no known geothermal resources capable of being developed for electrical generation on Vancouver Island or adjacent islands. Also, geological conditions suggest that there is little potential for high temperature geothermal resources in the area.

5.9 DISTRIBUTION

In December 1982, an internal report on distribution from Port Alberni to Bamfield was prepared by B.C. Hydro.[6,25] The report examined a 73 km, 3-phase, 25 kV extension of the Vancouver Island grid to Bamfield from China Creek, 10 km south of Port Alberni (Fig. A.5-20). It was assumed that the existing 12 kV line from Port Alberni to China Creek would be upgraded to 25 kV in 1985/86, independent of any extension to Bamfield. It was also assumed that the proposed 25 kV wood pole, distribution line would generally follow the existing gravel road thereby reducing clearing, installation and maintenance costs.

Much of the distribution line route is through areas that were previously logged and it passes by MacMillan Bloedel's Camp B (Franklin River) and this could be added to the electrical load. The result would be an increase of 250 kW in peak demand and approximately 30 MW·h in annual energy. It is possible that MacMillan Bloedel will develop a


ALBERNI
PORT ALBERNI
N
Alberni Inlet
Alma Russell Is
IMPERIAL EAGLE CHANNEL
TREVOR CHANNEL
Bamfield
Cape Beale
CONTOUR INTERVAL (IN FEET)
0
5
10
15 km
SCALE

LEGEND

PROPOSED DISTRIBUTION LINE ROUTE

B.C. HYDRO

FIGURE A.5 - 20

PROPOSED DISTRIBUTION LINE ROUTE BAMFIELD capacity of 150 kW from a small hydro site near Camp B. In that case they would have no requirement for connection to the B.C. Hydro system.

It is assumed that the diesel station at Bamfield would be dismantled once security of the new distribution line is proved. Two mobiles may be left behind for emergency power in case of an outage.

SECTION 6.0 - ENVIRONMENTAL FACTORS AFFECTING ALTERNATIVE ENERGY DEVELOPMENT AT BAMFIELD

6.1 INTRODUCTION

A preliminary evaluation of the environmental impacts of alternative energy resource development at Bamfield was conducted in conjunction with a preliminary engineering evaluation. The purpose was to determine any overriding environmental factors which would make a potential project unacceptable. This evaluation of environmental impacts consisted of a brief literature study and discussions with some government scientists and concerned residents of the community. Environmental impacts were examined for the following alternative sources of energy: small hydro, tidal, wind, thermal (wood waste, tree farms and coal) and transmission.

6.2 CLIMATOLOGY

The outstanding feature of the littoral climate of British Columbia is the mild and humid winters. For this latitude, the precipitation is heavy, particularly on the mountains. At low elevations frost is usually slight, but not unknown when continental polar air moves from the northern interior. On the coast snow falls only a few days in most winters, but it is damp and soon melts. In the mountains, the lower slopes almost to sea level, are under many feet of snow from November to March.

The rains decrease after March to a minimum in July and August which form a pronounced dry season with bright sunny days. The air is warm, but the sea-breeze assures that temperatures do not rise too high.

Toward the end of September the nights become cool, damp and sometimes foggy as the rainy season begins.

Climatic normals for temperature and precipitation in the Bamfield area are listed in Table A6-1. Wind data for Cape Beale, 6 km southwest of Bamfield, are documented in Fig. A.6-1. Surface winds are strongly influenced by topography. The Strait of Juan de Fuca to the southeast of Cape Beale and the Alberni Inlet to the northeast influence winds over the Bamfield area (Fig. A.5-1).

6.3 EXISTING RESOURCES

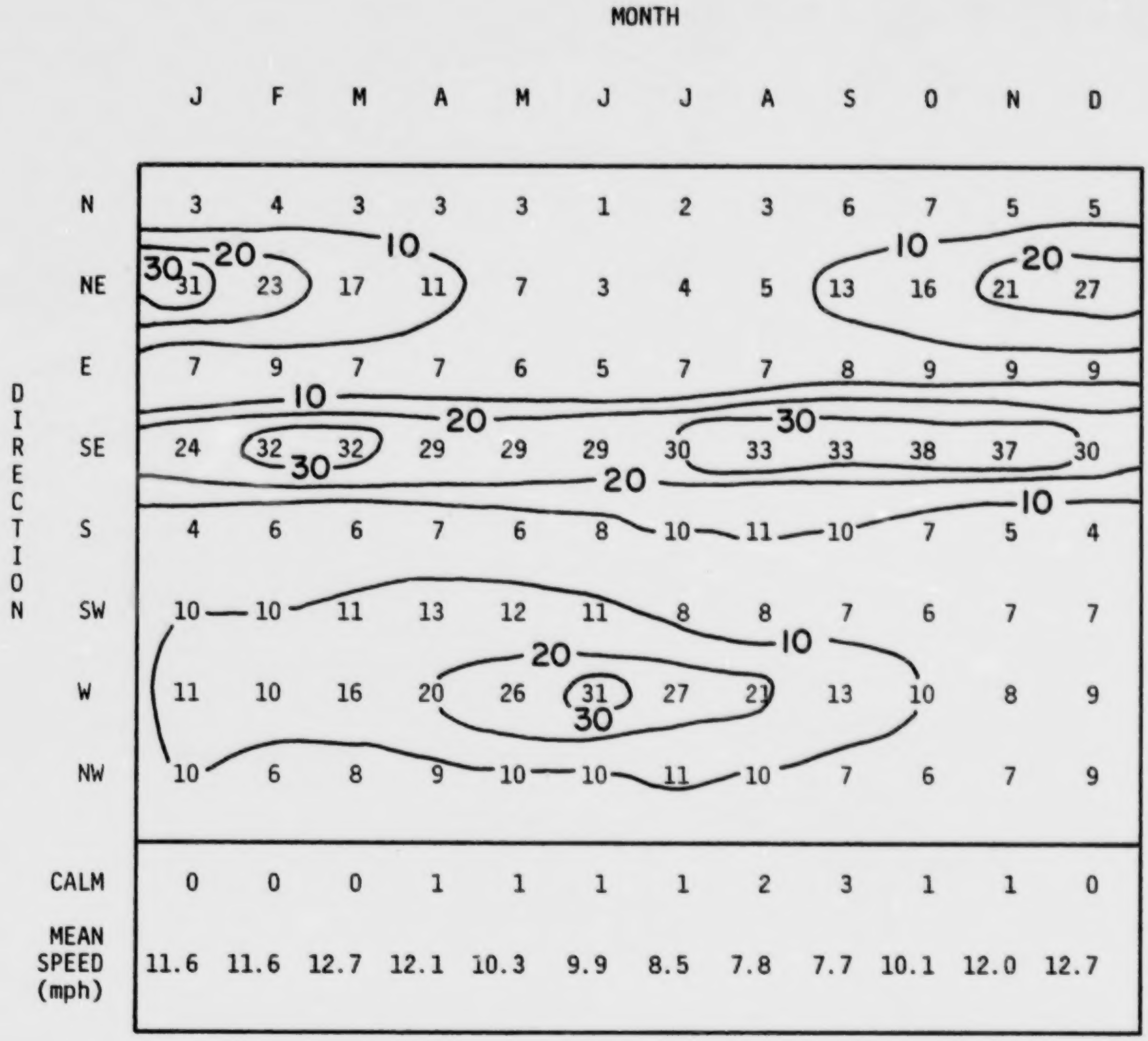
Bamfield is a small community of 211 people which is located on the west coast of Vancouver Island, approximately 90 km southwest of Port Alberni. The nearby Indian villages of Ancala and Pachena Bay are residence to an additional 262 persons bringing the area total to 473.

TABLE A6-1

BAMFIELD TEMPERATURE (°C) AND PRECIPITATION (mm) NORMALS

BAMFIELD EAST 48°50'N 125°7'W 4 m	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
Daily Maximum Temperature	6.9	8.9	9.5	11.2	13.6	15.7	17.8	17.9	17.4	14.0	10.1	7.7	12.5
Daily Minimum Temperature	1.0	2.2	2.0	3.7	6.2	8.8	10.4	10.7	9.0	6.5	3.6	2.2	5.5
Daily Temperature	4.0	5.6	5.8	7.5	9.9	12.2	14.0	14.3	13.2	10.3	6.8	5.0	9.1
Standard Deviation, Daily Temperature	1.4	1.2	0.9	0.9	0.8	1.0	0.6	0.8	1.1	0.8	1.0	1.4	0.4
Extreme Maximum Temperature	14.4	19.4	21.7	23.4	30.6	32.8	31.7	30.0	30.6	23.3	20.0	16.1	32.8
Years of Record	21	21	21	21	21	21	21	22	22	22	22	22	
Extreme Minimum Temperature	-9.4	-6.1	-3.9	-2.2	-0.6	2.2	4.4	4.0	0.0	-2.8	-4.4	-10.6	-10.6
Years of Record	21	21	21	21	21	21	21	22	22	22	22	22	
Rainfall	360.0	329.0	326.4	191.5	129.1	74.7	62.1	98.3	133.2	334.4	386.3	428.7	2853.7
Snowfall	12.2	1.5	2.3	T	0.0	0.0	0.0	0.0	0.0	0.0	0.8	8.4	25.2
Total Precipitation	372.2	330.5	328.7	191.5	129.1	74.7	62.1	98.3	133.2	334.4	387.1	437.0	2878.8
Standard Deviation, Total Precipitation	180.4	155.3	127.7	80.0	67.9	38.0	54.6	72.2	69.6	193.9	133.4	130.0	386.8
Greatest Rainfall in 24 hours	141.7	98.6	101.6	72.6	71.6	43.9	136.4	92.2	81.5	185.9	117.6	123.2	185.9
Years of Record	21	21	21	21	21	21	21	21	21	22	22	22	
Greatest Snowfall in 24 hours	16.5	7.6	12.7	T	0.0	0.0	0.0	0.0	0.0	0.0	6.4	22.9	22.9
Years of Record	21	21	21	21	21	21	21	21	22	22	22	22	
Greatest Precipitation in 24 hours	141.7	98.6	101.6	72.6	71.6	43.9	136.4	92.2	81.5	185.9	117.6	123.2	185.9
Years of Record	21	21	21	21	21	21	21	21	21	22	22	22	
Days with Rain	20	19	19	17	14	10	8	10	11	18	21	22	189
Days with Snow	3	-	1	0	0	0	0	0	0	0	-	2	6
Days with Precipitation	21	19	20	17	14	10	8	10	11	18	22	23	193

Source: Canadian Climate Normals (1951 to 1980)



DIRECTION	J	F	M	A	M	J	J	A	S	O	N	D
N	3	4	3	3	3	1	2	3	6	7	5	5
NE	31	23	17	11	7	3	4	5	13	16	21	27
E	7	9	7	7	6	5	7	7	8	9	9	9
SE	24	32	32	29	29	29	30	33	33	38	37	30
S	4	6	6	7	6	8	10	11	10	7	5	4
SW	10	10	11	13	12	11	8	8	7	6	7	7
W	11	10	16	20	26	31	27	21	13	10	8	9
NW	10	6	8	9	10	10	11	10	7	6	7	9
CALM	0	0	0	1	1	1	1	2	3	1	1	0
MEAN SPEED (mph)	11.6	11.6	12.7	12.1	10.3	9.9	8.5	7.8	7.7	10.1	12.0	12.7

Fig. A.6-1 - Percentage Frequency Wind Direction (and Calms) and Mean Wind Speed by Months - Cape Beale Lightstation, B.C. (Oct 1968 to Dec 1976).

Economic activity in the area is diverse. The area is becoming popular among tourists. Facilities include campsites and marinas, which service the sport fishing industry. Bamfield is also the northwestern terminus of the West Coast Trail, a challenging hiking trail located in the Pacific Rim National Park. Commercial salmon fishing is economically important and is serviced by a packing plant operated by J.S. McMillan Fisheries Ltd. and located on Bamfield Inlet. The Western Canadian Universities Marine Biological Station is an important part of the community. Bamfield is on the western edge of an active logging area operated by MacMillan Bloedel.

Bamfield is a unique community from a transportation standpoint. The community is spread over the shoreline of both Bamfield and Grappler inlets. The primary mode of transportation to the essential services on the Mills Peninsula (west side of Bamfield Inlet) is by boat (Fig. A.5-7).

6.4 SPECIFIC ENVIRONMENTAL EFFECTS

(a) Small Hydro

The Sarita River site (Fig. A.5-1) is at the western end of Sarita Lake where the river flows over a falls dropping a total of 43 m within 1 km. The river which is used by spawning salmon as far as the base of the falls is subject to sudden large variations in flow as a result of heavy precipitation over the steeply-rising terrain within the Sarita Lake catchment basin. The damaging effect of flood conditions is evident around the lake and further upstream where uprooted trees and debris are evident. Heavy rains and spring runoff are known to raise the lake above the road grade which skirts the southern shore. At higher elevations precipitation approaches 5000 mm/a with the bulk of this occuring in the winter months.

From the base of the falls to the ocean (9.7 km), the river and its tributaries are used by a variety of salmon species. Chum is the predominant species and spawners have been recorded in numbers ranging from 7500 to 75 000.[26] The Sarita River system has been studied for salmon enhancement since 1978.

The small hydro development proposed for the Sarita River site would be a "run-of-the-river" plant. Therefore, the natural variation in the water level and the flow of water in the river would not be substantially affected. Since the project would be upstream of the falls and would not alter river flows, the salmon resource would likely not be adversely affected.

The water fall is presently inaccessable to the public except by boat from Sarita Lake. Development of the site would provide public access to the falls and the lower river. Improved public access could result in increased steelhead sport fishing at the base of the falls where fish congregate.

Access to the area would likely require the widening and extension of an old logging road. The distribution line would generally follow existing roads thereby minimizing the land disturbance. The line would go through an active logging area. Therefore, any small additional land disturbance is expected to be insignificant.

(b) Tidal

Near Bamfield there are several potential sites which were examined for the utilization of tidal technology. These sites are Poett Nook, Grappler Inlet and Bamfield Inlet (Fig. A.5-6). Tidal development would result in the construction of a barrage-type structure which would isolate the basin from the main body of water, restricting navigation to slack tide periods.

The Dochapple Indian Reserve, located at the south end of Poett Nook, is the site of a recreational facility which is open to the public and provides camping facilities and a marina (moorage for 40 boats) for the sports fishery in Trevor Channel and beyond. Restricted access to Poett Nook created by a tidal barrage would essentially displace the existing campground and marina. Local reaction against the tidal development would likely result from the choice of this site. Compensation for business loss is possible, but at a significant cost.

Poett Nook Creek which flows northeast into Poett Nook is the spawning ground of approximately 1000 chum and smaller numbers of coho salmon.[26] These resources would likely be adversely affected by a tidal development. A small salmon enhancement program may be required to compensate for losses.

The shoreline of Grappler Inlet is used extensively for year-round residences. At present there are at least 20 residences and other buildings along the shores. The only access for some of these dwellings is from the water. Bamfield is a unique community in that the normal mode of travel is by boat. There is a government dock (Port Désiré) on the south side of Grappler Inlet. Much of the community obtains needed services by water access; these services include the hospital, school and post office. Because of the navigational interference posed by a tidal barrage, the Grappler Inlet site would likely be unacceptable without mitigation.

The lower 1 km of Sugsaw Creek (Grappler Creek) is a salmon spawning stream flowing into Grappler Inlet. In recent years this creek has had chum runs as high as 14 000. A small number of coho salmon also use the stream.

Another potential tidal site is on Bamfield Inlet near the northeast end of Burlo Island (Fig. A.5-7). There are a few residences up the inlet from the proposed site, but most of the upper end of the inlet is presently undeveloped and there is no known requirement for unrestricted navigation into the inlet. However, there are tentative plans for the development for a marina and campsite up the inlet. There are no salmon spawning streams flowing into Bamfield Inlet. The site does not appear to have any severe restrictions. However, the future marina plans would have to be explored more fully should the site be chosen for a detailed feasibility study.

(c) Wind

The unnamed hill 2 km southeast of Bamfield (Fig. A.5-9), near Pachena Bay, was selected in 1981 as a potential wind site and wind monitoring instruments were installed. The hill and surrounding terrain have been logged by MacMillan Bloedel Ltd. The area does not appear to have been replanted as yet. Land use conflicts with MacMillan Bloedel would potentially be an environmental concern requiring resolution. Noise from the wind machine would require study to determine the levels at nearby residences. Distribution from the site would be mostly along existing roadways and would not result in significant impacts.

(d) Thermal

Wood and coal have been considered as potential fuels for a thermal generating station located at Roquefeuil Bay northeast of Bamfield (Fig. A.5-14). The environmental factors associated with wood waste and or tree farms are primarily socio-economic in nature. Increased local employment would result from wood waste gathering and tree farm operations; however, the specialized labor force required to operate a thermal facility would not necessarily benefit the local population in terms of jobs. The Bamfield area is a developing tourist, recreational and alternate life style area. Therefore, the installation of a thermal facility may be perceived by some segments of the local population as undesirable.

Emissions of gaseous, liquid and solid wastes from a thermal facility would be limited by a Waste Management Act permit. Wood waste generated by logging operations is presently piled and burned at the dry land sorts. Therefore, the use of this material in a controlled combustion furnace would likely reduce emissions in the area.

The operation of a tree farm would require approximately 1300 ha or 13 km^2 to provide a sustained yield for a 1 MW wood-fired thermal plant. Land use conflicts may result because existing timber leases cover most of the area near Bamfield which would be suitable for tree farming. Turbidity in streams and lakes within the tree farms could result from harvesting operations.

The Roquefeuil Bay site is presently accessible by an existing logging road running southwest from Sarita. However, distribution from the site would require a more direct right-of-way to Bamfield.

(e) Distribution

The supply of electricity to the Bamfield area from the Vancouver Island grid system would require the construction of a distribution line from a point 10 km south of Port Alberni and extending 73 km to Bamfield. The route would follow the existing road from Port Alberni to Bamfield in order to minimize costs and land use conflicts. The road, which was built mostly by MacMillan Bloedel and is maintained by them, is primarily used by logging trucks as a haul route.

Construction of a distribution line right-of-way along the route would require close cooperation with logging companies and the public to minimize disruption to logging activities and to access to Bamfield. Although the streams in the area provide spawning and rearing habitat for anadromous fish, the effects of distribution line construction on fish and wildlife would be minimal because new access road construction would not be required. The heavy rainfall which occurs in the study area creates the need for contol of sedimentation during both the construction and the maintenance of the line.

(f) Economic Geology

(i) Introduction

The regional geology, locations of mineral showings and deposits and mineral deposit land use were examined in order to determine the potential impacts of alternative energy developments and/or distribution line routes on mineral exploration and exploitation in the Port Alberni-Bamfield area. There are numerous mineral showings and deposits of base metals, precious metals and industrial minerals in the area and still more could be discovered.

(ii) Regional Geology

Bamfield is in the Insular Belt of British Columbia. The rocks of the Insular Belt consist of deep ocean tholeiitic basalts, marine argillites and limestones, Jurassic island arc assemblages, Cretaceous shallow marine clastic rocks, Early Tertiary arc assemblages and plutonic rocks.[24,26]

pendants of Vancouver Group limestone and volcanic rocks lie within a diorite intrusion. The limestone is replaced for approximately 800 m along and near the diorite contact. On the west end of the pendant the mineralization is clean magnetite, but there is increasing garnet, pyrite, pyrrhotite, marcasite and chalcopyrite toward the east.

The Copper King (15) and WW (17) showings are approximately 8 km up Coleman Creek from the Alberni Inlet. The mineralization on the Copper King property is in a sheared zone which is as much as 60 m wide. The sheared zone contains an irregular zone of hornblende, garnet, epidote and quartz containing pods of massive pyrrhotite 1.8 m to 2.4 m wide. The strike of the mineralization is 040° to 080° and it dips 50°NW. The best mineralization is in the northwest wall of the sheared zone, but chalcopyrite is disseminated throughout. The property has been explored by numerous pits and shafts and a pod of chalcopyrite 2 m wide was found in one adit. The mineralization on the WW property is along a fault which separates Bonanza(?) andesite from Quatsino(?) limestone. The fault zone is 0.6 m wide and it has been traced for 30 m. The mineralization consists of chalcopyrite, pyrite and pyrrhotite in an actinolite skarn.

The Copper Prince (16) showing is west of the road from Port Alberni and at the point where the road enters the valley of Coleman Creek. The mineralization consists of a narrow vein of chalcopyrite which occupies a fissure in quartz diorite. The vein has been traced for more than 100 m. Several openings have been made into the vein.

The Gambler (30) showing is 3 km east of Sarita River. The bedrock consists of intensely sheared Quatsino limestone replaced by garnet-diopside-epidote skarn. The skarn is mineralized with pyrrhotite which has inclusions of chalcopyrite and minor bornite and tetrahedrite. The Omar claim group is associated with the Gambler showing and it contains silicified, sheared zones in Bonanza volcanic rocks. The volcanic rocks contain lenses of magnetite and zones with pyrrhotite and minor chalcopyrite.

The Canadian (66) showing is above Parsons Creek, 24 km south of Port Alberni. The bedrock consists of granodiorite which contains two lenses of chalcopyrite in sheared zones. These lenses are approximately 800 m from a limestone contact.

The Star of the West (67) prospect is adjacent to Corrigan Creek. The showings contain quartz-pyrite veins in a biotite granodiorite dyke and Karmutsen basalts. The mineralization consists of chalcopyrite in veinlets which are 3.0 to 6.0 mm wide. The outcrops have a strong gossan stain on them.

Vancouver Island is divided into numerous blocks by northeast and northwest-trending faults (Fig. A.6-2 and Table A6-2). Movements along most of the faults have not been defined. The oldest rocks in these blocks are part of the Upper Paleozoic(?) Westcoast Complex. The Complex consists of quartz diorite, diorite, tonalite, amphibolite, agmatite and minor metavolcanic and metasedimentary rocks. It forms a wide belt on the west side of Vancouver Island. The Westcoast Complex is overlain unconformably or is in fault contact with the Middle(?) and Upper Triassic Karmutsen Formation. The Karmutsen Formation consists mostly of pillow basalts, breccia, tuff and minor flows and with the overlying Quatsino Formation it comprises a wide almost continuous belt through central Vancouver Island. The Middle(?) and Upper Triassic Quatsino Formation consists of limestone with minor calcareous siltstone, shale, cherty limestone and chert. The Quatsino Formation is overlain unconformably by the Lower Jurassic Bonanza Group. The Bonanza Group is exposed on central Vancouver Island where it consists of basaltic to rhyolitic tuff, breccia, flows, sills and dykes as well as minor argillite and greywacke.

Other rock units which are exposed in the map area include some Upper Paleozoic(?) limestones and Eocene and Oligocene clastic sedimentary rocks of the Carmanah Group.

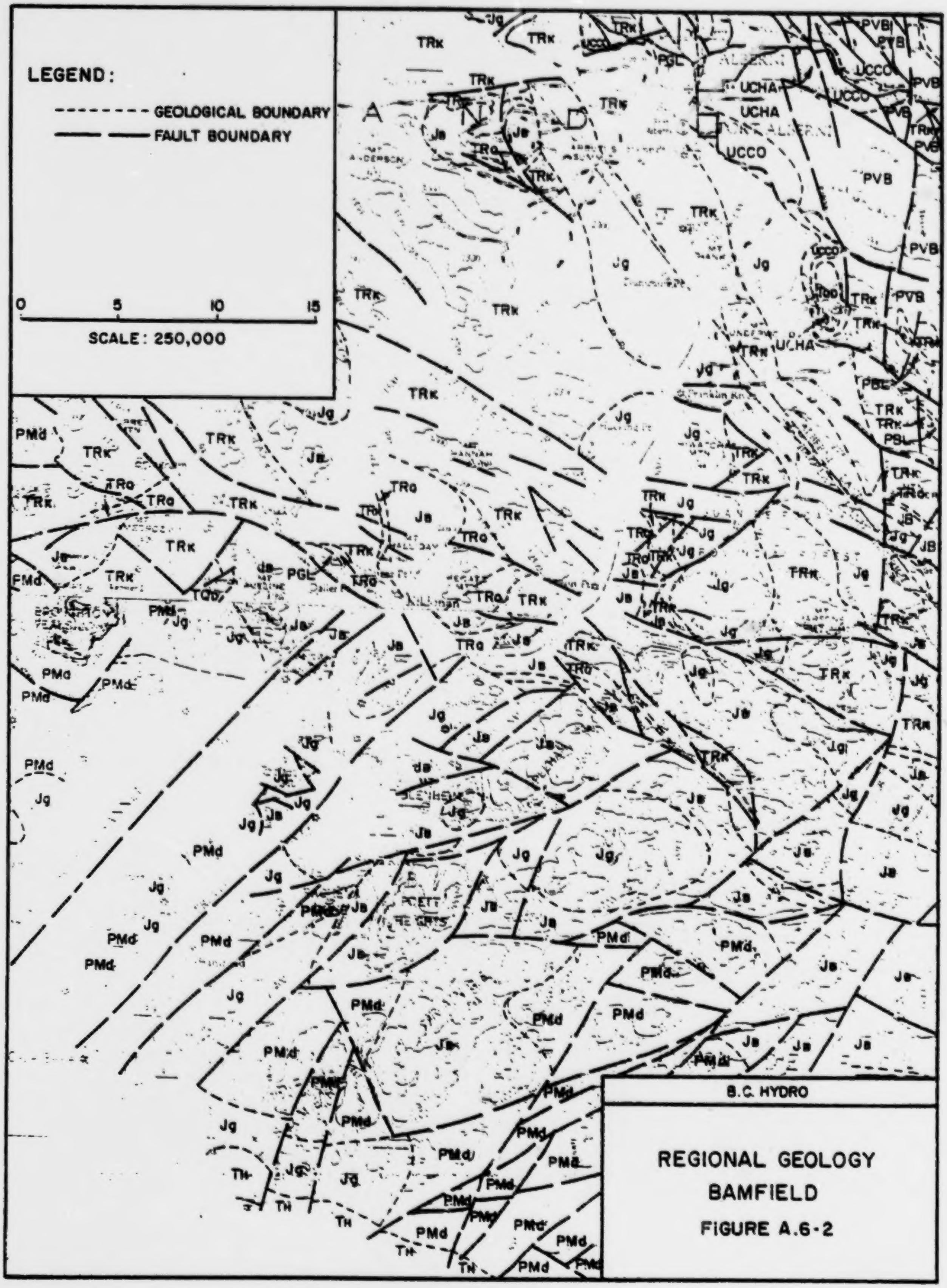
(iii) Mineral Deposits

The mineral deposits of the Bamfield area are summarized in Table A6-3 and their locations illustrated in Fig. A.6-3. Eleven of these showings could be affected by the installation of a distribution line from Port Alberni to Bamfield and one showing could be affected by the construction of a thermal plant at Roquefeuil Bay.[28]

The eleven showings which could be affected by a distribution line from Port Alberni to Bamfield are Doer (6), Sarita (9), Copper King (15), Copper Prince (16), Gambler (30), Canadian (66), Star of the West (67), WW (17), Cor 14 (85), Cor 6 (86) and Parsons Creek (89).

The Doer (6) showing is 1.5 km south of the mouth of the Sarita River at El. 90 m. The mineralization consists of magnetite with pyrrhotite, pyrite, arsenopyrite, chalcopyrite, sphalerite, malachite, azurite and possibly tetrahedrite. The mineralization is in a skarn-like replacement zone in Quatsino limestone adjacent to a contact between Bonanza(?) volcanic rocks and a quartz diorite intrusion.

The Sarita (9) showing is approximately 0.5 km northeast of the Doer showing, near the mouth of the Sarita River. Roof


LEGEND:
GEOLOGICAL BOUNDARY
FAULT BOUNDARY
0
5
10
15
SCALE: 250,000
ALBERNI
PORT ALBERNI
TRK
TRa
Jg
Js
PMd
PGL
PVB
UCCO
UCHA
PBL
JB
TQb
TH

B.C. HYDRO

REGIONAL GEOLOGY
BAMFIELD
FIGURE A.6-2

TABLE A6-2

TABLE OF FORMATIONS

CENOZOIC

QUATERNARY

PLEISTOCENE AND RECENT

PGL	Glacial and alluvial sand, gravel and till

TERTIARY

EOCENE AND OLIGOCENE

CARMANAH GROUP:

TH	Hesquiat Formation - siltstone, shale, sandstone and conglomerate
TQD	Hornblende quartz diorite, leucoquartz monzonite, porphyritic dacite, breccia

MESOZOIC

UPPER CRETACEOUS

UCHA	Haslam Formation - shale, siltstone, fine sandstone
UCCO	Comox Formation - sandstone, conglomerate, shale and coal

LOWER TO UPPER JURASSIC

Jg	Island Intrusions - biotite-hornblende granodiorite, quartz diorite

LOWER JURASSIC

BONANZA GROUP:

JB	Basaltic andesitic, latitic and rhyolitic tuffs, breccias, flows, sills and dykes, argillite, greywacke and limestone

UPPER TRIASSIC

VANCOUVER GROUP:

TRQ	Quatsino Formation-may include some Parson Bay Formation limestone, minor calcareous siltstone, shale, cherty limestone and chert
TRK	Karmutsen Formation-pillow basalt, massive flows, breccia, minor tuff, jasperoid tuff and conglomerate

TABLE (continued)

PALEOZOIC	
UPPER PALEOZOIC AND/OR (?) TRIASSIC AND JURASSIC	
ls	Recrystallized limestone and skarn
PMd	Westcoast Complex-quartz diorite, diorite, tonalite, amphibolite, agmatite minor metavolcanic and metasedimentary rocks
LOWER PERMIAN	
	SICKER GROUP:
PBL	Buttle Lake Formation-limestone, chert
PENNSYLVANIAN AND OLDER	
PVB	Volcanic breccia, tuff, argillite, greenstone, greenschist, dykes and sills of porphyritic andesite

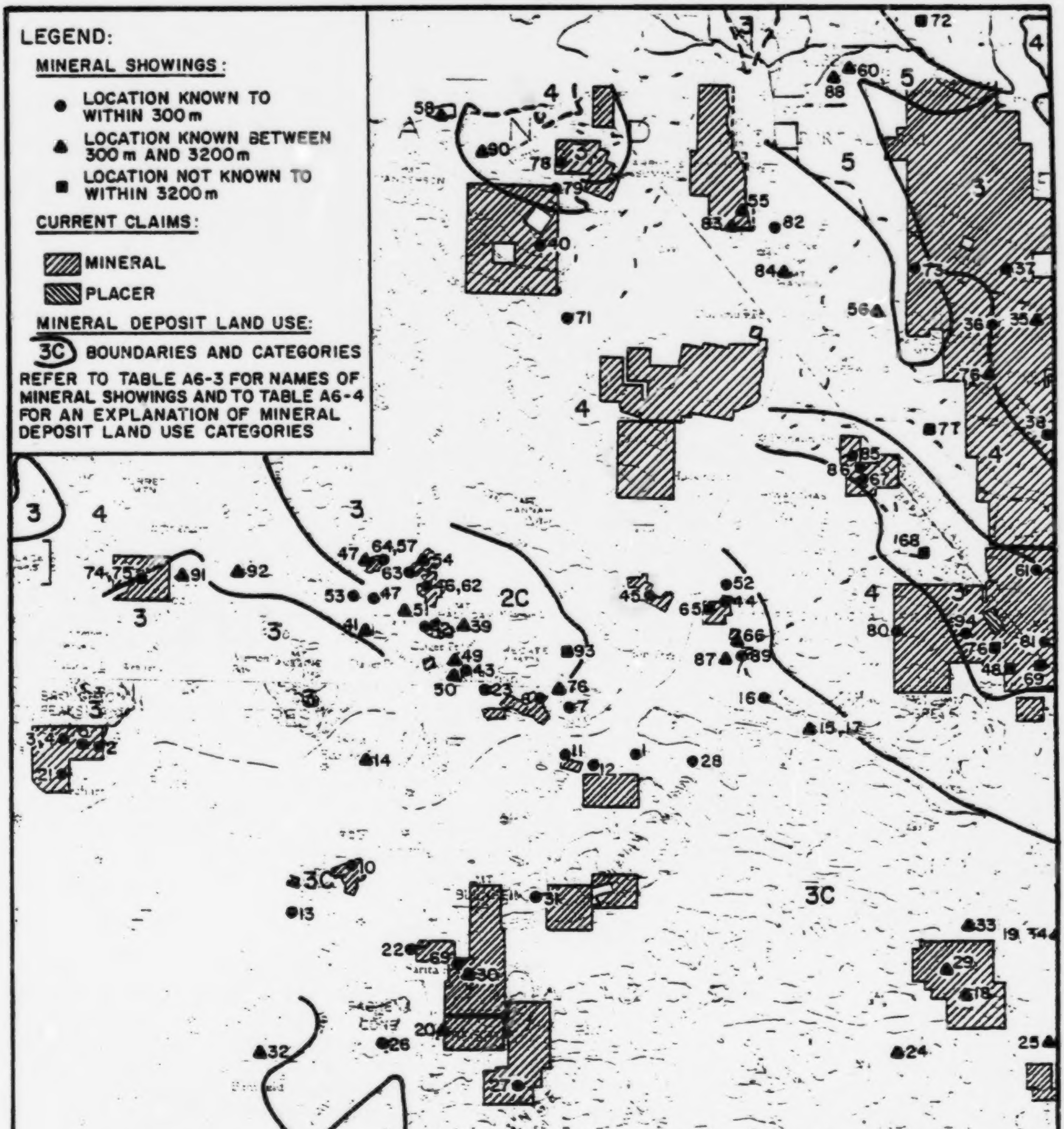
TABLE A6-3

MINERAL SHOWINGS NEAR BAMFIELD

Showing No.	Name	Formation	Product(s)
NTS Map 92C			
1	Koros	Quatsino	Cu, Pb, Zn
2	Crown Prince	Bonanza	Fe
3	Iron Chief	Paleozoic(?) Limestone	Fe
4	Bald Eagle	Paleozoic(?) Limestone	Fe
5	Lord of the Isles	Quatsino	Fe
6	Doer	Quatsino	Fe, Cu, Zn
7	Monitor	Quatsino-Bonanza	Cu, Ag
8	Happy John	Quatsino-Bonanza	Cu, Fe
9	Sarita	Quatsino	Cu, Au, Ag
10	Mountain (Copper Island)	Quatsino-Karmutsen	Fe
11	Gladys	Quatsino	Cu, Au, Ag
12	Edith	Quatsino-Island Intrusions	Ag, Cu
13	Marble Cove	Quatsino-Island Intrusions	Cu
14	Sudbury Pacific	Island Intrusions	Ni
15	Copper King	Bonanza	Cu
16	Copper Prince	Bonanza	Cu
17	WW	Bonanza	Cu
18	Flora	Bonanza	Cu, Ag
19	Panther	Quatsino	Cu
20	Dean	Quatsino	Cu
21	Sechart (Balmoral, Azogic)	West Coast Complex	Hg
22	Santa Maria Island	Bonanza	Cu
23	Southern Cross	Quatsino-Bonanza	Cu, Ag
24	Klanawa and Canyon	Bonanza	
25	MJ, NICU, T.B.	Bonanza	Cu
26	DAC (PC)	Island Intrusions	Mo, Cu
27	SR	Bonanza	Mo
28	Spencer Creek	Quatsino-Bonanza	Cu, Ag

Showing No.	Name	Formation	Product(s)
29	Ni	Karmutsen	Cu, Pb, Zn
30	Gambler, Omar	Quatsino-Bonanza	Cu, Ag
31	Bus	Bonanza	Cu, Fe
32	Barkley Sound	Quatsino	Limestone
33	A.B.C. Summit	Quatsino	Pb, Zn, Cu, Ag
NTS Map 92F			
35	Thunderbird	Island Intrusions	Au
36	Regina	Pennsylvanian(?) Volcanics	Au, Cu, Ag
37	Victoria	Pennsylvanian(?) Volcanics	Au, Ag, Cu
38	Thistle	Buttle Lake	Au, Ag, Cu
39	Black Prince	Bonanza	Fe
40	Kola	Karmutsen	Cu
41	Sentinel	Quatsino	Cu, Pb, Zn
42	Torse (Bluebell)	Quatsino-Karmutsen	Cu
43	Sunshine	Quatsino	Fe, Cu
44	Kitchener (Island Copper)	Karmutsen	Fe, Cu, Ag
45	Three Jays (Hayes, Nahmint)	Karmutsen	Cu, Ag, Fe, Au
46	Belvidere	Quatsino	Fe, Cu
47	Lake Shore	Quatsino	Fe, Cu
48	Golden Slipper	Island Intrusions	Au, Ag, Cu
49	Saucy Lass (Thunderbolt)	Quatsino	Cu, Fe
50	Cascade	Bonanza	Cu, Ag
51	Ivanhoe	Quatsino	Cu
52	Darby-Joan	Karmutsen	Fe
53	Big Bluff	Karmutsen	Cu
54	Rainy Day	Karmutsen	Cu, Fe
55	Dauntless	Karmutsen	Au, Ag, Cu
56	Grizzly	Island Intrusions	Au, Ag, As
57	Mountain Tressure (Forfarshire)	Bonanza	Cu
58	Ferguson	Karmutsen	Au
59	Defiance	Island Intrusions-Quatsino	Fe
60	Port Alberni	Haslam	Shale, Clay
61	Mary	Karmutsen-Quatsino	Cu, Mo, Zn
62	Orphan Boy	Quatsino	Fe, Cu
63	Florence	Karmutsen	Cu
64	Marmot	Bonanza	Cu
65	Union Jack	Quatsino	Cu
66	Canadian	Island Intrusions	Cu

Showing No.	Name	Formation	Product(s)
67	Star of the West	Island Intrusions-Karmutsen	Au, Cu, Zn
68	Starlight	Island Intrusions	Au
69	Andy	Island Intrusions	Cu, Mo
70	Golden Rule	Island Intrusions	Au, Ag, Cu
71	Rex	Karmutsen	Mo, Cu
72	Cameron Lake	Sicker	Fe
73	Duke of York	Recent Sands and Gravels	Placer Au
74	Chris 1	Karmutsen-Quatsino	Cu
75	Chris 2	Quatsino	Cu
76	Ken	Karmutsen(?)	Cu
77	BDQ	Island Intrusions	Au, Ag, Cu
78	A North	Quatsino	Cu
79	A South	Quatsino-Karmutsen	Cu
80	Lofstrom	Karmutsen	Cu
81	Mount Olsen	Island Intrusions-Karmutsen	Cu
82	Campbell	Karmutsen	Cu
83	BK 136G	Karmutsen	Cu
84	Copper Mountain (Mt. Hankin)	Karmutsen	Cu
85	Cor 14	Island Intrusions	Cu, Au
86	Cor 6	Island Intrusions	Cu, Au
87	Mor	Bonanza	Cu
88	Rogers Creek	Recent	Clay
89	Parsons Creek	Quatsino	Limestone
90	Sproat Lake	Quatsino	Limestone
91	Effingham Inlet	Quatsino	Limestone
92	Ellingham Inlet	Karmutsen	Jasper
93	Hecate Mountain	Quatsino	Limestone
94	WWW	Island Intrusions	Au, Ag, Cu



LEGEND:

MINERAL SHOWINGS:

- ● LOCATION KNOWN TO WITHIN 300 m
- ▲ LOCATION KNOWN BETWEEN 300 m AND 3200 m
- ■ LOCATION NOT KNOWN TO WITHIN 3200 m

CURRENT CLAIMS:

- ▨ MINERAL
- ▧ PLACER

MINERAL DEPOSIT LAND USE:

- (3C) BOUNDARIES AND CATEGORIES

REFER TO TABLE A6-3 FOR NAMES OF MINERAL SHOWINGS AND TO TABLE A6-4 FOR AN EXPLANATION OF MINERAL DEPOSIT LAND USE CATEGORIES

B.C. HYDRO

MINERAL SHOWINGS, CLAIMS AND DEPOSIT LAND USE BAMFIELD

FIGURE A.6-3

The Cor 14 (85) and Cor 6 (86) prospects lie on alternate sides of the road along Corrigan Creek. On the Cor 14 prospect there is a large pit and a short adit which exposes quartz-carbonate veins cutting Karmutsen greenstone and slaty metasedimentary rocks. Sulphides are not abundant, but pyrite, chalcopyrite and arsenopyrite have been observed. The best of 11 assays contained 0.09 percent Cu and 0.85 g/t Au. On the northern part of the Cor 14 prospect the gold-bearing vein is exposed over 15 m. On the Cor 6 prospect a drift follows a quartz-carbonate vein which is 0.15 m to 1.0 m wide, strikes 055° and dips 40°E. The host for the vein is Karmutsen greenstone. The vein contains sparsely disseminated sulphides, mainly pyrite and chalcopyrite. Assays range from 0.7 g/t to 2.06 g/t gold and 0.02 percent to 0.51 percent copper. The property has been explored by drifting, trenching and by a main adit which is 12.6 m long.

The Parsons Creek (89) prospect is along Parsons Creek, approximately 2 km from Alberni Inlet. The prospect contains an irregular band of impure Quatsino limestone which extends to Alberni Inlet.

There is one showing which could be affected by the construction of a thermal plant in the area. The Barkley Sound (32) showing is along the shore and south of Roquefeuil Bay. There are numerous, similar, small deposits of limestone along the shores of Barkley Sound. These limestone deposits may be suitable for sulphur absorption in a thermal plant.

Most of the remaining prospects in the area contain mineralization in quartz veins which were injected along sheared zones. There are a number of other prospects which contain skarn-type deposits along intrusive-limestone or intrusive-volcanic contacts. In this area the deposits tend to be small, but they are abundant.

(iv) Discussion

Maps for mineral deposit land use planning[28,29] (Fig. A.6-3 and Table A6-4), mineral showings (Table A6-3) and mineral claims can be related to geology (Fig. A.6-2 and Table A6-2) and the areas of highest mineral potential can be predicted. Most of the area is designated Category 3C which indicates that there are no significant mineral deposits known, but the geological environment is favourable for the discovery of small deposits, and present and future exploration are expected. The area around Bamfield and along the coast is designated Category 4 which indicates areas where the status is undetermined, but where there is probably some mineral potential.

TABLE A6-4

CATEGORIES OF MINERAL DEPOSIT LAND USE

AREA CLASS	
1	AREA CONTAINING OREBODIES IN PRODUCTION OR ABOUT TO GO INTO PRODUCTION; GEOLOGIC ENVIRONMENT HIGHLY FAVOURABLE; AREA OF INTENSIVE EXPLORATION. 1A LARGE DEPOSITS KNOWN OR PROBABLE 1B MEDIUM DEPOSITS KNOWN OR PROBABLE 1C SMALL DEPOSITS KNOWN OR PROBABLE
2	SOME DEPOSITS KNOWN; TYPE OF OCCURRENCE AND GEOLOGICAL ENVIRONMENT FAVOURABLE; SOME EXPLORATION AT ADVANCED STAGES; CONTINUED EXPLORATION. 2A LARGE DEPOSITS POSSIBLE 2B MEDIUM DEPOSITS POSSIBLE 2C SMALL DEPOSITS POSSIBLE
3	NO SIGNIFICANT DEPOSITS KNOWN; GEOLOGICAL ENVIRONMENT FAVOURABLE; PRESENT AND FUTURE EXPLORATION LIKELY. 3A LARGE DEPOSITS POSSIBLE 3B MEDIUM DEPOSITS POSSIBLE 3C SMALL DEPOSITS POSSIBLE
4	SOME INDICATION OF MINERAL POTENTIAL; GEOLOGIC STATUS INDETERMINATE AT PRESENT; EXPLORATION POSSIBLE.
5	NO INDICATION OF MINERAL POTENTIAL; EXPLORATION UNLIKELY.
D	SAND, GRAVEL, CLAY, ALLUVIUM, TILL OR DRIFT WHICH COVER AREAS OF VARIED MINERAL POTENTIAL.

(v) Conclusions

It is concluded that there are no significant conflicts between mineral development and any of the alternatives to diesel electrical power generation at Bamfield. The geology is favourable for the discovery of small deposits of base and precious metals as well as for the development of limestone quarries. However, none of these have been developed to date. There are likely to be local sources of limestone for sulphur sorption if this is required.

SECTION 7.0 - ENERGY COSTS

7.1 INTRODUCTION

Energy cost estimates were made for the alternatives to diesel generation which appear to be technically feasible. These alternatives are small hydroelectric generation at Sarita River, tidal generation at Bamfield Inlet, wind generation near Pachena Bay, wood-fired thermal, wood gasification-engine and coal-fired thermal generation near Roquefeuil Bay and distribution from Port Alberni.

7.2 DIESEL

The construction cost of the building, facilities and mobiles at the Bamfield diesel generating station is $1.207 million (Table A7-1). The plant burns No. 2 fuel oil which in December 1983 cost $0.365/L (Table A7-2). The capital cost of the plant is low, but the overall cost of energy is high at 161 mills/kW·h. The high energy cost is because of the high cost of fuel. The fuel cost is approximately 75 percent of the cost of energy (1984 $) assuming December 1983 fuel costs and projected 1990/91 fuel consumption.

7.3 SMALL HYDROELECTRIC

The proposed site selected for small hydroelectric development is on the Sarita River 19 km northeast of Bamfield. The construction cost of a small hydroelectric generating facility is summarized in Table A7-3.

It is assumed that an access road 2 km long would be constructed at a cost of $40,000/km. No significant environmental impacts are expected, but an environmental cost allowance is made in order to safeguard the salmon stocks during construction. The penstock is assumed to consist of 655 m of series 45 polyethylene pipe at a cost of $82,000/km, 145 m of series 60 polyethylene pipe at a cost of $107,000/km and 100 m of steel pipe at a cost of $100,000/km; there are additional allowances of $85,000 for labor and equipment, $51,000 for indirect costs and a $34,000 remote location allowance, resulting in an estimated cost of $255,000. The intake is estimated to cost $170,000, $51,000 is allowed for indirect costs and $34,000 for a remote location allowance; the cost of the intake structure is estimated to be $200,000, the tail race $30,000, the crane $25,000, electrical works $50,000 and transportation of material $20,000. Indirect costs are estimated to be $97,000 and a remote location allowance of $65,000 is estimated for a total cost of $487,000. A 1.0 MW, 700 rpm turbine-generator unit is estimated to cost $550,000. Controls are estimated to cost $40,000, indirect costs would

TABLE A7-1

CONSTRUCTION COSTS FOR THE BAMFIELD DIESEL GENERATING STATION

	CONSTRUCTION COST (k$)[*1]
Station Building and Facilities	372
Mobiles	835
Total	1207

[*1] Asset value (March 1982).

TABLE A7-2

SUMMARY OF COMPARATIVE ENERGY COSTS[*1] - BAMFIELD

	Diesel Bamfield	Small Hydroelectric Sarita River	Tidal Bamfield Inlet	Wind Pachena	Thermal Wood Roquefeuil Bay	Thermal Wood-gas Roquefeuil Bay	Thermal Coal Roquefeuil Bay	Distributio Port Alber Bamfield
Plant and Distribution Characteristics								
Plant Capacity (MW)	1.7	1.00	0.50	0.30	1.00	1.00	1.00	1.80
Capacity Factor (%)	31	53	32	6	53	53	53	-
Annual Energy (GW·h)	4.65	4.65	1.40	0.16	4.65	4.65	4.65	4.65
Type of Fuel	No. 2 Fuel Oil	-	-	-	Wood	Low-Btu Gas	Coal	-
Cost of Fuel	$0.365/L $9.31/GJ	-	-	-	$69.15/t[*7] $4.12/GJ	$69.15/t[*7] $4.12/GJ	$61.25/t $2.38/GJ	-
Construction Period (a)	-	2	2	2	2	2	2	1
Plant Life (a)	20	40	40	20	35	20	35	-
Distribution Life (a)	30	30	30	30	30	30	30	30
Capital Costs								
Plant Construction Cost (k$)[*2]	1 207	3 437	5 958	1 206	5 372	4 136	4 751	-
New Distribution Construction Cost (k$)[*2]	-	915	34	60	225	225	225	2 990
New Substation Construction Cost (k$)[*2]	-	150	-	-	290	290	290	-
Total Construction Cost (k$)[*2]	1 207	4 502	5 992	1 266	5 887	4 651	5 266	2 990
Project Cost ($/kW)[*3]	710	5 903	14 374	4 643	6 476	5 116	5 793	1 993
Total Capital Cost (k$)[*4]	1 207	6 505	7 927	1 518	7 255	5 686	6 411	3 911
Annual Costs								
Operation and Maintenance Cost (k$)[*5]	113	147	183	29	468	301	337	322[*8]
Fuel Cost (k$)	546[*6]	-	-	-	316	370	137	-
Amortization Cost (k$)	89	339	401	111	391	409	346	226
Total Annual Cost (k$)	748	485	583	140	1 175	1 080	899	548
Gross Unit Energy Cost (mills/kW·h)	161	104	416	872	253	232	193	118

[*1] At 4 percent net interest rate.
[*2] Including engineering.
[*3] Includes construction and contingency.
[*4] Includes construction, contingency, overhead and I.D.C.
[*5] Includes taxes.
[*6] The equivalent energy cost of No. 2 fuel oil is 117 mills/kW·h.
[*7] Oven-dried tonne.
[*8] Includes electrical energy cost.

TABLE A7-3

CONSTRUCTION COSTS FOR THE PROPOSED SARITA RIVER SMALL HYDROELECTRIC GENERATING STATION

(k$)

Land and Water Rights	100
Access Road and Clearing	150
Camp Costs	180
Environmental	50
Penstock	255
Intake	255
Powerhouse	487
Turbine-Generator Unit	885
Installation	130
Surge Tank	100
Instrumentation	80
Miscellaneous	75
Subtotal	2747
Engineering at 25%	690
Total Plant and Construction Cost	3437
Transformer/Switchgear	150
Transmission	915
Total Transmission - Substation Cost	1065
Total Construction Cost	4502

be $177,000 and a remote location allowance is estimated to be $118,000 for an approximate total of $885,000. Installation is expected to cost $130,000. The costs of surge tank and instrumentation are estimated to be $100,000 and $80,000 respectively. Miscellaneous costs including backfilling are estimated to be $75,000. The subtotal for the plant costs is $2,747,000. A 25 percent allowance is also made for engineering.

The cost of a 25 kV distribution line to Bamfield is expected to be $40,000/km over a distance of 23 km. The route would follow the existing road where possible. The cost of a transformer and switchgear are listed in Table A7-3.

The overall construction cost for a small hydroelectric plant and associated transmission is estimated to be $4,502,000. Fixed costs are taken as a percentage of the uninflated total construction cost and variable charges are related to energy production as summarized in Table AC2-1 and Appendix D. The gross unit energy cost for small hydroelectric generation at Sarita River near Bamfield is estimated to be 104 mills/kW·h.

7.4 TIDAL

Simplified cost estimating procedures have been developed for small, low head hydroelectric installations[31] and these have been used for tidal installations in this report because of a lack of documented cost estimates for small tidal installations. The cost estimates for dyke and sluiceway components were estimated from the Bay of Fundy tidal studies.[32] The basic unit costs for these components are as follows:

- dykes: $50/m^3 of fill
- sluiceway: $60,000/m^2 of discharge area

Distribution costs have been estimated at $50,000/km for construction of 3-phase, 25 kV overhead circuits.

The construction cost for the layout described above is shown in Table A7-4. The estimate includes all direct costs plus allowances for engineering (12%).

Annual operation and maintenance costs are difficult to forecast accurately, primarily because no data are available for small tidal projects. For small hydro plants a rough estimate of operation and maintenance costs are estimated to be 1.2 percent of the plant capital cost[31] which covers routine operation and maintenance (labor, equipment and parts), insurance and general expenses. It is assumed that this procedure could be applied to estimate similar costs for small tidal developments.

TABLE A7-4

CONSTRUCTION COSTS FOR BAMFIELD INLET TIDAL GENERATING STATION (k$)

Access and Site Preparation	115
Dykes	1690
Sluiceway	740
Powerhouse	
Turbine-Generator	1550
Civil Works	865
Electrical and Miscellaneous Equipment	360
Subtotal	5320
Engineering at 12%	638
Total Plant Construction Cost	5958
Transformer and Switchgear	180
Transmission and Substation	30
Total Transmission - Substation Cost	210
Total Construction Cost	6168

Operation and maintenance costs and other annual charges, (e.g. school taxes) for the proposed Bamfield Inlet plant are shown in Table A7-2 and considered in more detail in Appendix D. The gross unit energy cost for tidal generation at Bamfield is estimated to be 416 mills/kW·h.

7.5 WIND

The cost estimate for wind generation at Bamfield is based on using six 50 kW vertical axis wind turbines manufactured by DAF Indal. The installed cost for the wind turbines is $201,000 each based on estimates in Tennis (1983).[14] It is assumed that a 3-phase, 25 kV distribution line to the existing diesel station would be required at a cost of $60,000. Most of this line would be along the road from Bamfield to Pachena Bay, parallel to the existing line and the remainder would be through a recently logged area.

The fixed costs together with the capital costs are summarized in Table A7-2 and Appendix D. The gross unit energy cost for wind generation at Bamfield is estimated to be 872 mills/kW·h.

7.6 THERMAL

(a) Wood Thermal

(i) Bamfield Wood Fuel Costs

The processed wood fuel costs for a thermal generating station at Roquefeuil Bay are summarized in Table A7-5. The most economical wood fuel source for Bamfield appears to be logging residue recovered from landings during active logging and/or collected along the logging roads. The cost of approximately $69.15/ODtonne (at a 4 percent net discount rate) is based on conventional residue recovery using a choker skidder/self-loading logging truck system.

Alternative residue recovery systems using large wood waste container systems[33] could conceivably reduce this cost by approximately $15.85/ODtonne to $53.30/ODtonne.

(ii) Wood-Fired Thermal Plant Costs

A summary of wood-fired thermal plant costs is listed in Table A7-6. The overall construction cost of a 1 MW wood-fired thermal powerplant at Roquefeuil Bay near Bamfield is estimated to be $5,372,000. Similarly, the combined cost of a substation and distribution over 5 km is estimated to be $515,000.

TABLE A7-5

BAMFIELD THERMAL GENERATING STATION
PROCESSED WOOD FUEL COST[*1]
SUMMARY

(Costs in March 1984 Canadian Dollars per over-dried tonne)

Cost Item	Source of Raw Wood Fuel (6000 OD/tonne/a)			
	Logging Residue From Landings and Logging Roads (Average Distance 32 km)[33]	Logging Residue From China Creek Land Sort (Barging Distance 42 km)[18]	Logging Residue From Caycuse Land Sort (Hauling Distance 95 km)[18]	Tree Farm at Roquefeuil Bay (Average Distance to Station 9 km)[34]
Stumpage or Salvage Value[*2] of Wood for Fuel	$ 3.13	$ 3.13	$ 3.13	$ 3.13
Tree Farm Operation	-	-	-	22.69
Harvesting	-	-	-	5.64
Yarding	21.98	-	-	-
Loading)	19.70	15.90	15.90	-
Truck Hauling)		-	41.29[35]	12.49[35]
Barging and Unloading	-	36.06[*3]	-	-
Supervision and Administration	5.87[18]	5.87[18]	5.87[18]	18.96
Preprocessing and Hogging[36] to Storage	18.47	18.47	18.47	-
Hogging or Chipping to Storage	-	-	-	17.65[30]
Total Cost of Wood Fuel (10% moisture content) Delivered to Station Storage Area	$69.15/ODtonne	$79.43/ODtonne	$84.66/ODtonne	$80.56/ODtonne
Cost of Green Wood Fuel (50% moisture content) Delivered to Station Storage Area	$38.42/tonne ($4.12/GJ)	$44.13/tonne ($4.73/GJ)	$47.03/tonne ($5.04/GJ)	$44.76/tonne ($4.80/GJ)

[*1] Processed wood fuel is assumed to have a 50 percent wet moisture content and does not include drying. Cost estimates are at a 4 percent net discount rate.

[*2] Discussions with the B.C. Forest Service indicated that a nominal charge of $0.10 to $1.25 per m³ could be applied to tree farm or salvage operations.

[*3] Barging costs based on a barge being made available for 14 days of loading per trip with a turn around barging time of 3 days - requiring 6 trips per year.

TABLE A7-6

BAMFIELD WOOD-FIRED THERMAL PLANT CONSTRUCTION COST ESTIMATE (k$)

	Material	Labor	Total
Boiler (including auxiliary equipment and piping)	1096	227	1323
Turbine-Generator (including auxiliary equipment and piping)	652	45	697
Feedwater System (including heaters, deaerators, etc.)	123	30	153
Cooling Water System (including pumps and trash screens)	23	5	28
Water Treatment Plant (including chemical equipment, storage tanks and demineralizers)	62	18	80
Fuel and Ash Handling (including conveyors and storage silos)	387	97	484
Miscellaneous (including vacuum pumps, air compressors, etc.)	45	25	70
Building and Structures	95	32	127
Site Preparation			120
Foundations and Concrete			200
Mechanical			260
Electrical, Instrumentation and Controls			300
Painting and Insulation			90
Vehicles			700
Hog Fuel Dryer (installed)			50
Engineering at 15%			690
Subtotal			5372

TABLE A7-6 - (Cont'd)

	Material	Labor	Total
Substation			
Site Preparation and Service	45	90	135
Transformer Position	74	53	127
Circuit Breaker Position	28	incl	28
Subtotal			290
Distribution (5 km at $45,000/km)			225
Total Construction Cost*[1]			5887

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*[1] Plant capacity is for a total net output of 1 MW. Gross output would be approximately 20 percent greater to allow for unit auxiliary and station service requirements. Annual fuel cost estimates are for the gross plant output.

The fixed and variable costs are summarized in Table A7-2 and Appendix D. The resulting unit energy cost is estimated to be 253 mills/kW·h.

(b) Wood Gasification-Engine Generation Costs

A summary of plant costs for a gas-fired engine generator is summarized in Table A7-7. The wood fuel costs are for logging residue recovered along logging roads and from landings (Table A7-5). The overall construction cost of a 1 MW wood gasifier and reciprocating engine electrical generating plant at Roquefeuil Bay near Bamfield is estimated to be $4,136,000. Similarly, the combined cost of a substation and distribution over 5 km is estimated to be $515,000.

The fixed and variable annual costs are summarized in Table A7-2 and Appendix D. The high fixed and variable costs are due to the operation of the gasifier. The unit energy cost for this method of generation is estimated to be 232 mills/kW·h.

(c) Coal-Fired Thermal Plant Costs

Coal for a coal-fired thermal plant is assumed to come from the East Kootenay region of British Columbia via Roberts Bank. It is assumed that a barge could be loaded at the Roberts Bank coal loading facility or at another facility in Vancouver. The cost of coal is estimated to be $46/t F.O.B. Roberts Bank. The tug and barge charges are estimated to be $25,000/trip. It is assumed that the tug and barge combination could carry 2230 t of coal, the quantity required for 1 years operation of the plant. There is allowance for a 16 h demurrage charge of $275/h on each trip. It is assumed that a front end loader comes with the barge at a cost of $75/h for standby and $113/h when operating. It is expected that there would be travel time of 37 h (round trip) and standby of 16 h at the site plus 8 h for off-loading. The charges for a tug, barge and loader have been escalated to reflect higher discount rates as summarized in Appendix D, although only 4 percent is used here.

A summary of construction costs for a coal-fired thermal plant are summarized in Table A7-8 and a summary of all costs and relevant data are listed in Table A7-2 and Appendix D. The construction cost of a coal-fired thermal plant at Roquefeuil Bay is estimated to be $4,751,000. Similarly, the combined cost of a substation and transmission over 5 km is estimated to be $515,000.

The fixed and variable annual costs are summarized in Table A7-2 and Appendix D. The unit cost of energy for a coal-fired thermal plant at Roquefeuil Bay is estimated to be 193 mills/kW·h.

TABLE A7-7

BAMFIELD WOOD GASIFIER - ENGINE GENERATOR
THERMAL POWER STATION CONSTRUCTION COST ESTIMATE
(k$)

Fuel Handling and Storage Facilities	366
Fuel Drying Facilities	86
Imbert Power Plant Package (1 MW)[*1]	2480
Ash Handling and Disposal Facilities	118
Buildings and Offsite Facilities (@ 6%)[*2]	183
Land and Site Preparation (@ 4%)[*2]	122
Civil Installations	200
Mechanical Installations	178
Electrical and Instrumentation Installations	250
Engineering (@ 5%)[*2]	153
Subtotal	4136
Substation	290
Transmission (5 km @ $45,000/km)	225
Total Construction Cost	4651

[*1] Package based on 4 Imbert Powerplant Systems with a heat rate of 17 500 GJ/GW·h, rated at 250 kW (net) each and consisting of:

a dryer and wood fuel feed system,
an Imbert wood gasifier (Type 688),
a cyclone and scrubber gas clean-up system,
a gas cooler and electrostatic filter,
a start-up gas blower, and
two 128 kW spark-gas engine generator sets.

Gross output would be approximately 10 percent greater to allow for unit auxiliary and station service requirements. Annual fuel cost estimates are for the gross plant output.

[*2] The percentages relate to the sum of costs for the first four items in the table.

TABLE A7-8

BAMFIELD COAL-FIRED THERMAL PLANT CONSTRUCTION COST ESTIMATE (k$)

	Material	Labor	Total
Boiler (including auxiliary equipment and piping)	1015	210	1225
Turbine-Generator (including auxiliary equipment and piping)	652	45	697
Feedwater Package (including heaters, deaerators, and pumps)	123	30	153
Cooling Water Package (including pumps, piping and trash screens)	23	5	28
Water Treatment Plant (including chemical equipment, and demineralizers)	62	18	80
Fuel and Ash Handling (including conveyors, storage silos, etc.)	369	92	461
Miscellaneous (including vacuum pumps, air compressors, etc.)	45	25	70
Buildings and Structures	95	32	127
Site Preparation			120
Foundations and Concrete			200
Mechanical			260
Electrical, Instrumentation and Controls			300
Painting and Insulation			90
Vehicle (truck)			250
Engineering			690
Subtotal			4751

TABLE A7-8 - (Cont'd)

	Material	Labor	Total
Substation			
Site Preparation and Service	45	90	135
Transformer Position	74	53	127
Circuit Breaker Position	28	incl	28
Subtotal			290
Distribution (5 km at $45,000/km)			225
Total Construction Cost*1			5266

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*1 Processed wood fuel is assumed to have a 50 percent wet moisture content and does not include drying. Cost estimates are at a 4 percent net discount rate.

7.7 DISTRIBUTION

The cost estimate for a 25 kV, 3-phase distribution line from China Creek, near Port Alberni, to Bamfield is summarized in Table A7-9. The cost of the line is $2,990,000 which assumes that it closely follows the existing road and that only limited clearing would be required because of the presence of the road and because much of the line would be through logged areas where the trees are generally small.

It is assumed that the diesel plant would be dismantled and there is no salvage value for the diesel plant because it consists of mobiles. However, some mobiles may be left at the present plant site in case of an outage on the line from Port Alberni. The fixed costs and variable costs are listed in Table A7-2 and Appendix D. The unit energy cost for distribution from Port Alberni is estimated to be 118 mills/kW·h.

7.8 PAYBACK PERIOD

(a) Introduction

An explanation of the term payback period, as it applies in this report is provided in Appendix C, Section 3. The costs used in estimating the payback period assume a 4 percent net discount rate.

The sizes and installation dates of new generating units proposed in this section have not been optimized. Optimization could modify the results sufficiently to reduce the payback period and change the relative economics of two closely priced alternatives. Reducing the load growth would have a severe impact on new alternatives, particularly those with high capital costs even if they are capable of providing for large increases in electrical demand.

Based on the energy costs (Table A7-2) only small hydroelectric generation and distribution appear to be competitive with diesel generation at Bamfield. These alternatives were selected for comparing their cumulative net cash flows and determining their payback periods (Fig. A.7-1). The cumulative net cash flow is estimated by taking the investment for the year, adding the interest charge at 4 percent net and subtracting the annual net benefit. The annual net benefit is the difference between the cost of energy from diesel and the cost of energy from an alternative. The time required for the cumulative net cash flow to equal zero is the payback period.

(b) Diesel

The annual diesel fuel cost assumes that the cost of fuel will remain essentially constant (increase at the rate of inflation) through 1986/87 and escalate at 1 percent per annum (net of

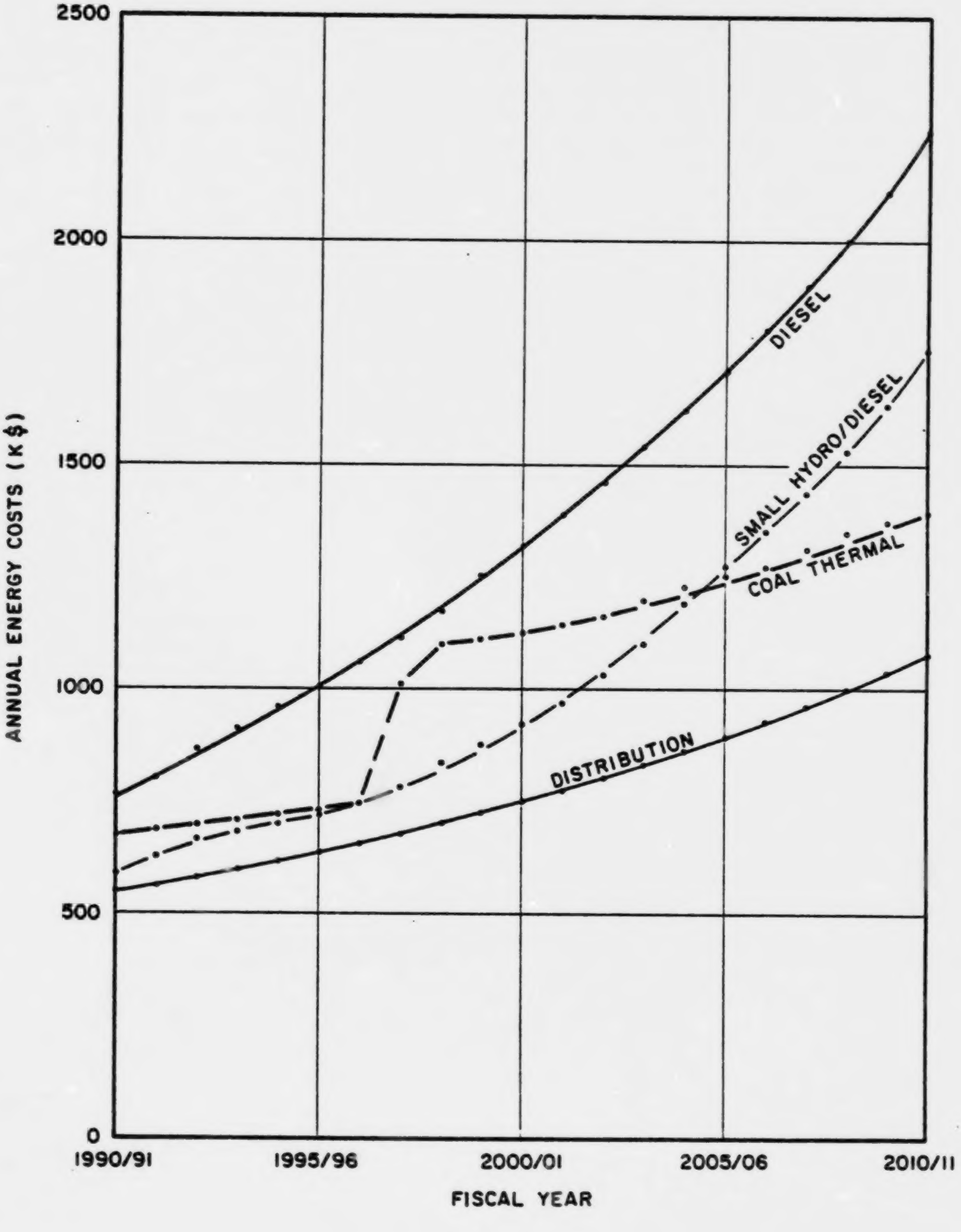
TABLE A7-9

COST ESTIMATE FOR A DISTRIBUTION LINE TO BAMFIELD (k$)

Distribution Line (3-phase, 25 kV - 73 km @ $41,000/km; including right-of-way and clearing where required)	2990
Salvage Cost for Diesel Plant	Nil
Substation	Nil
Total Construction Cost	2990

FIGURE A.7-1

ANNUAL ENERGY COSTS - BAMFIELD



inflation) thereafter. The fuel is consumed at a rate of 0.313 L/kW·h and the cost of lube oil is estimated to be 3.28 percent of the fuel cost (based on 1982/83 fuel consumption rates for the Bamfield diesel generating station). The estimates assume that the growth rates of the peak demand and annual energy remain constant at 5.3 percent and 5.0 percent respectively through the period 1990/91 to 2010/11. Further, the estimates assume that new 600 kW diesel generating units would be added in 1993/94, 2001/02 and 2007/08 to ensure that the peak demand could be met. Annual costs other than amortization are assumed to increase in proportion to the annual energy.

(c) Small Hydroelectric

Small hydroelectric power generation on the Sarita River would be sufficient to meet both the peak demand and annual energy in 1990/91. The 1 MW generating capacity is sized to utilize the low flows in the summer and meet the peak demand in 1990/91. It is also assumed that only one diesel generating unit (600 kW) would be left at the diesel generating station to provide emergency power. However, the growth in peak demand would require additional generation and these are assumed to be 600 kW diesel generating units which would be added in 1992/93, 2000/01, 2006/07 in order to ensure sufficient capacity with one diesel generating unit out of service. For the diesel generating units annual costs, excluding amortization, are assumed to be proportional to the amount of service. It is assumed that the diesel units would pick up 10 percent of the load between 1990/91 and 1996/97; thereafter it is assumed that all of the new load would be picked up by diesel generation. The amortization cost for the diesel generation is assumed to increase as new units are added. For the small hydroelectric generation, the annual costs, exclusive of amortization, are decreased by 10 percent to allow for the load picked up by the diesel generation. The costs of small hydroelectric generation are assumed to be constant over the time interval. The cumulative net cash flow for small hydroelectric/diesel generation is plotted in Fig. A.7-1. The net benefit of small hydro is initially negative, but in 1993/94 the net benefit becomes positive. The payback period for small hydroelectric generation on the Sarita River is estimated to be in excess of 20 years.

(d) Distribution

A 25 kV, 3-phase distribution line from Port Alberni (China Creek) could supply the load required by Bamfield. It is assumed that the diesel station would be dismantled and the salvage value would offset the cost of dismantling the station. The annual costs other than the cost of electricity from the grid remain constant over the period illustrated in Fig. A.7-1. The cost of electricity is assumed to increase in proportion to the increased load. The cumulative net cash flow is summarized in Fig. A.7-1. Distribution would provide the most economical method of serving the electrical load at Bamfield. The payback period is estimated to be approximately 12 years.

SECTION 8.0 - DISCUSSION

8.1 INTRODUCTION

The status of the diesel generating station at Bamfield was examined for a 1990/91 load in order to compare the costs with alternative methods of generation such as small hydroelectric, tidal, wind, thermal (wood, wood-gasification and coal) and a distribution line.

8.2 DIESEL

The present diesel generating station consists of three units with a capacity of 1.7 MW. These units are mobiles which permit easy replacement for major overhauls and repairs. Similarly, new units can be added to the station as required. The gross unit energy cost for the diesel generating station in 1990/91 is estimated to be 161 mills/kW·h and the equivalent energy cost for diesel fuel is estimated to be 117 mills/kW·h. The rapid escalation in the cost of diesel fuel, beginning in September 1980 has seen the price more than double in just over 2 years. The price is presently very unstable because of the recession, but it is not expected to undergo a sustained rise for the next few years, then it is expected to rise at 1 percent per annum (net of inflation).

The diesel station is in a location where noise from the station does have a significant impact on the local residents. There are few other environmental problems with diesel generation.

8.3 SMALL HYDROELECTRIC

A 1 MW small hydroelectric generating station at the Lower Falls on the Sarita River could provide 4.65 GW·h/a in 1990/91 and as much as 6.1 GW·h/a when demand is higher in the future. The size of the plant is restricted by low summer flows on the Sarita River. If additional work is undertaken to examine small hydro development on the Sarita River it would be necessary to optimize the size of the plant to the size of the river flows and the revised load forecasts.

Small hydroelectric development alone could not supply the required electrical energy and supplementary diesel generation would be necessary if this alternative were selected. The addition of the diesel generation would significantly increase the overall cost of the small hydroelectric alternative from 104 mills/kW·h to 127 mills/kW·h. Unfortunately, although the topography of the site makes it favorable for small hydroelectric development, the site is 19 km from Bamfield which results in the distribution line comprising 20 percent to the total construction cost. By allowing for supplementary diesel generation small hydroelectric generation is not the most economical alternative to diesel generation, but it could still be appreciably more economical than diesel generation in the future. The payback period is estimated to be more than 20 years based on a 1990/91 in-service date.

The environmental impacts of small hydroelectric development would not be significant provided the water level of Sarita Lake would not be raised. Raising the lake level would flood a large area east of the lake, parts of some campgrounds and result in more frequent flooding of the road to Bamfield. The generating station would be at the base of the lower falls on the Sarita River. This falls is impassable to salmon; therefore, the impact of a small hydroelectric development on the Sarita River is not expected to be significant.

8.4 TIDAL

A 500 kW tidal generating station on Bamfield Inlet was examined briefly as a potential source of electrical power for Bamfield. The intermittent nature of tidal power reduces the estimated capacity factor to 32 percent and the tidal generating station would produce only 1.4 GW·h/a of electrical energy. It would be necessary to have diesel or another form of reliable generation to supplement tidal generation and provide electrical power during periods of slack tides. Therefore, tidal power is simply a fuel saver which would have a high capital cost. The gross unit energy cost in 1990/91 is estimated to be 416 mills/kW·h, which is appreciably more than the cost of diesel generation.

The environmental impacts of tidal development on Bamfield Inlet could be considerable. A tidal development would block access to the open ocean for a few residents up the inlet from the proposed tidal development. A new marina is also proposed for the upper part of Bamfield Inlet and this would not be compatible with tidal development.

8.5 WIND

In 1981 the National Research Council and B.C. Hydro constructed a wind monitoring station on a hill overlooking Pachena Bay. In this study the site was selected for a proposed wind farm having six 50 kW vertical axis wind turbines. Unfortunately, the combination of the wind in general being intermittent and the Bamfield site in particular having an unfavorable wind regime causes the annual energy to be only 158 MW·h. The overall unit energy cost of 872 mills/kW·h is the highest of the alternatives examined for Bamfield. Wind generation creates fluctuations in the distribution system; therefore, its contribution must be restricted in order to minimize these fluctuations.

Diesel generation would be required in order to provide supplementary electrical power much of the time and all of the electrical power when wind velocities are low. The required diesel generation would further increase the cost of a wind/diesel combination.

The principal environmental impact of wind generation is the land alienation. Approximately 9 ha would be required for a 300 kW wind farm consisting of six 50 kW units. This land would be unavailable for the development of forestry resources which is the present land use. The site was recently logged.

8.6 THERMAL

(a) Wood

A wood-fired thermal plant at Roquefeuil Bay could supply any amount of electrical energy by increasing the plant size, but the increasing energy would be realized at a disproportionately increasing cost. The present estimate for the cost of wood-fired thermal power generation is 253 mills/kW·h and it is based on obtaining wood from nearby roadsides and landings. Increased wood-fired thermal power generation would require transportation from more distant wood sources.

Some diesel generation would be required in order to provide black start capability. This requirement would further increase the cost of wood-fired thermal power generation.

The construction cost of a wood-fired thermal plant is high because of the low heating value of the fuel and the large boiler required to utilize this fuel. The operating costs are somewhat higher than for other alternatives partly because of the requirement for having licenced personnel for a steam plant.

The environmental impacts of a thermal plant would not be significant because of its small size. It is assumed that the plant would meet emission standards set by legislation and guidelines. Once-through cooling would result in a temperature rise around the cooling water discharge point, but the effect would be local because of water circulation in the Alberni Inlet and the small size of the plant. Boiler water make-up (fresh water) would be required from a lake, river, or well near the proposed plant site. The land alienation is estimated to be approximately 2 ha. Benefits of wood-fired thermal power generation would include the additional cleaning of roadsides and landings and the resulting improved utilization of the wood resource.

(b) Wood Gasification-Engine Generation

A wood gasification-engine generating plant at Roquefeuil Bay could supply any amount of electrical power by increasing the plant size, but the increase in plant size would increase the construction cost as well as the unit cost of wood fuel. Many of the problems associated with a wood gas-engine generating plant are similar to those associated with a wood-fired thermal plant. In order to increase the electrical supply, wood must be brought from farther away and at increased cost. The construction cost for a wood gas-engine generating plant would be less than for a wood-fired thermal plant, but the efficiency would be less. The overall unit energy cost is estimated to be 232 mills/kW·h, which is 20 percent more than for coal-fired thermal power generation. The latter would be the most economical method of thermal power generation.

A small amount of diesel power generation would be required in order to provide black start capability and for security.

The environmental impacts for wood gasification-engine generation are similar to those for wood-fired thermal generation. Land alienation is estimated to be approximately 2 ha.

(c) Coal

A coal-fired thermal plant at Roquefeuil Bay could provide any amount of electrical energy by increasing the plant size and barging more coal from Roberts Bank or Vancouver. There is essentially no limitation on the fuel supply and the delivered unit coal cost would decrease from the estimated cost of $61.25/t as the quantity of coal is increased. The gross unit energy cost is estimated to be 193 mills/kW·h for coal-fired thermal power generation. However, an allowance was made for diesel power generation to provide peaking and black start capability. It was assumed that approximately 10 percent of the electrical energy would be produced by diesel units.

The emissions for coal-fired thermal generation would be similar to wood-fired thermal generation, but there would be some additional SO_2 emissions, although these would be within legislated limits or guidelines. Land alienation is estimated to be approximately 2 ha.

8.7 DISTRIBUTION

A 25 kV, 3-phase distribution line has been proposed from Port Alberni (China Creek) to Bamfield and it should be installed in 1986/87. It is estimated that this line, which would be 73 km long, would provide the most economical alternative to diesel power generation at Bamfield. The gross unit energy cost for the distribution line is estimated to be 118 mills/kW·h, which is more than the estimated cost of electrical energy from a small hydroelectric development on the Sarita River. However, the distribution line would be capable of providing for future electrical demand, whereas only part of this future demand could be supplied by a small hydroelectric generating plant on the Sarita River. The capital cost of a distribution line is estimated to be one of the lowest of the alternatives that were examined. The payback period for the distribution line is estimated to be 12 years.

A distribution line could be constructed without difficulty along the existing access road from Port Alberni to Bamfield. Much of the route is through previously logged stands of young trees. The only significant environmental impact would be the loss of forestry values because of the land alienation.

SECTION 9.0 - CONCLUSIONS

In assessing alternatives to diesel power generation at Bamfield alternative fuels (for the diesel generators), small hydroelectric, ocean wave, tidal, wind, solar, wood thermal, wood gasification-engine generation, coal thermal, geothermal and distribution were examined. Alternative fuels are not considered practical for the existing generating station and ocean wave and solar technologies are not sufficiently developed. No geothermal resources are known to occur near Bamfield.

On the basis of gross unit energy costs the following alternatives were identified as being more economical than diesel power generation (in order of increasing cost): small hydroelectric (104 mills/kW·h) and a distribution line (118 mills/kW·h). Small hydroelectric generation would require significant supplementary diesel generation; therefore, based on a 1990/91 in-service date, the payback period is estimated to be more than 20 years and small hydroelectric generation would not be as economical as distribution. A 25 kV, 3-phase distribution line would not require supplementary diesel once the security of the line is assured. The payback period for distribution, based on a 1990/91 in-service date, is 12 years.

No serious environmental impacts were identified for the small hydroelectric or distribution line alternatives. It is assumed that each alternative would meet all government regulations and guidelines to protect the environment.

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PART B: ALTERNATIVE ENERGY OPTIONS FOR SUPPLYING ELECTRICAL POWER TO BELLA BELLA

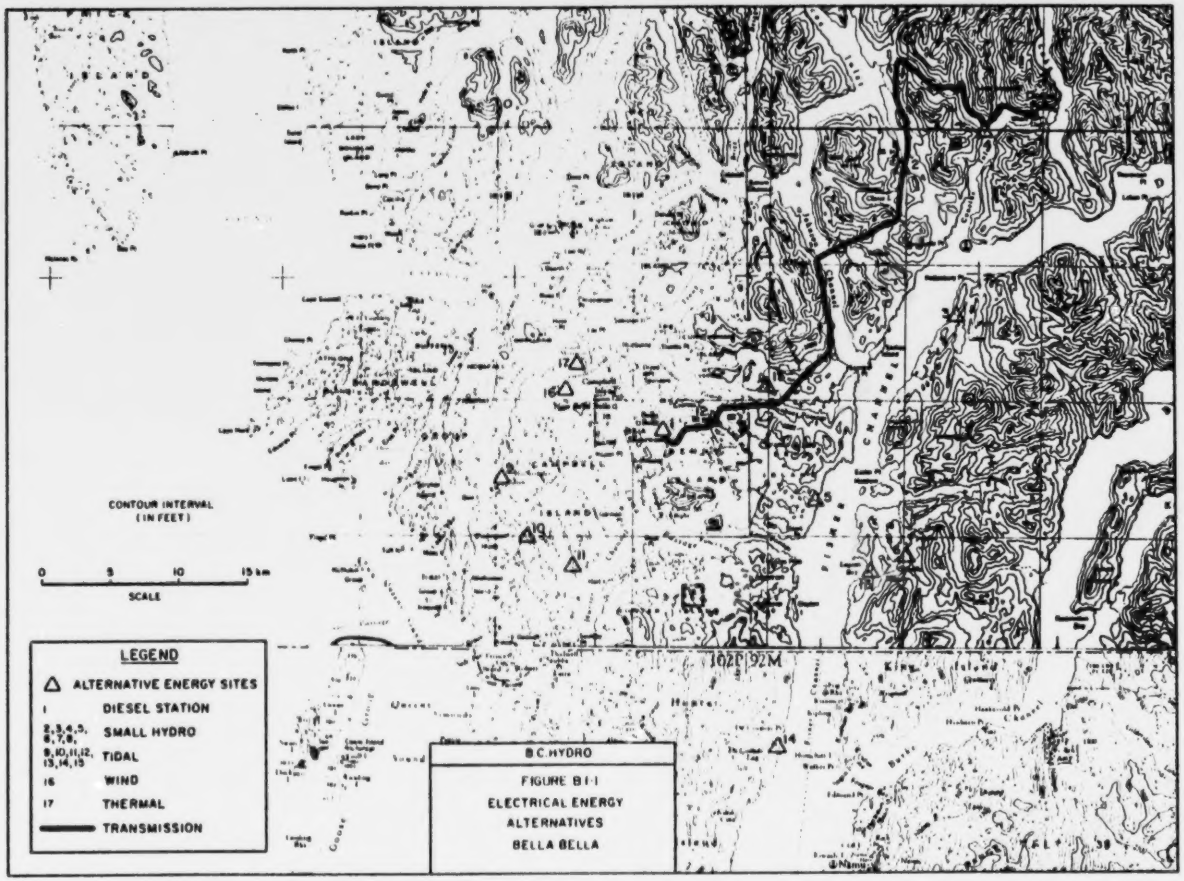
SECTION 1.0 - INTRODUCTION

The Bella Bella diesel generating station serves the communities of New Bella Bella, East Bella Bella and Shearwater. New Bella Bella is on Campbell Island and East Bella Bella and Shearwater are on Denny Island (Fig. B.1-1). All of these communities are approximately 37 km southeast of Ocean Falls. Denny Island and Campbell Island are separated by Lama Passage which is as little as 0.6 km wide. There is no road access to the islands, but there are scheduled plane flights from Vancouver and a ferry from Port Hardy.

The terrain is particularly rugged near Ocean Falls with mountains rising from sea level to more than 1000 m. The terrain is flatter toward Bella Bella where muskeg and small lakes are common. Isolated mountains such as the Williams Range, the highest point on Denny Island, rise to approximately 520 m. The highest point on Campbell Island is Mount Hand which is more than 300 m high. Mount Hand and the Williams Range form part of a northwest-trending line of low mountains on Denny, Campbell and Horsfall Islands. Long narrow channels separate the various islands and cut into the coastal mainland resulting in numerous, narrow, deep fjords.

The history of centralized electrical power generation in the area goes back to 1954 when a study by the B.C. Power Commission summarized the generating facilities near Bella Bella.[1] At one time there was a 75 kW diesel generator at New Bella Bella; however, immediately prior to the 1954 study this generating facility was destroyed in a fire. Many people on the Indian Reserve at New Bella Bella had their own small diesel generators. B.C. Packers had two 15 kW generators at East Bella Bella. There was a 25 kW, 120/208 V diesel generator in a 9 m by 15 m powerhouse at Shearwater. These facilities were not integrated and incapable of satisfactorily meeting the total load.

In 1963 a more comprehensive examination of the generating facilities in the area was completed by B.C. Hydro.[2] At that time there were four independent electrical power systems. New Bella Bella village had a 100 kW Delco generator providing 3-phase a.c. power at 120/208 V. The generator was run daily from dawn to dusk. The power output was distributed to the village on a wood pole line. The United Church Hospital, also on Campbell Island, had one 25 kW Kato light plant and one 35 kW Gardner stand-by plant. These generators produced single phase power at 120/240 V. The two units were not synchronized to operate in parallel. The plant operated 24 hours per day and served only the hospital by means of a wood pole line. B.C. Packers, on Denny



B.C.HYDRO

FIGURE B1-1
ELECTRICAL ENERGY
ALTERNATIVES
BELLA BELLA

LEGEND
△ ALTERNATIVE ENERGY SITES
1 DIESEL STATION
2,3,4,5,6,7,8, SMALL HYDRO
9,10,11,12,13,14,15 TIDAL
16 WIND
17 THERMAL
TRANSMISSION
CONTOUR INTERVAL (IN FEET)
0 5 10 15 km
SCALE
CAMPBELL ISLAND
FISHER CHANNEL
Johnson Channel
102P 92M
King Island
Queens Sound
Goose
Hunter

Island, had two 15 W Kato light plants, one of which was on stand-by. The generating plant provided 3-phase power at 120/240 V to the fish plant and single phase power at 120 V to the federal fisheries office and residence by means of a wood pole line. Widsten Marine Services at Shearwater had a 40 kW Palmer generator and a 20 kW Perkins generator on stand-by; both were supplying 3-phase power. The plant operated from 7:00 a.m. to 11:00 p.m. daily. It used the old R.C.A.F. distribution line, but this line was in poor condition. At the abandoned R.C.A.F. powerhouse there were two stripped generators and a switchboard which were in disrepair and it was uneconomical to rebuild any of them.

In 1969 the generating facilities and requirements were examined once again.[3] New facilities had been installed in the Bella Bella area. These included the replacement of the 25 kW Kato light plant at the hospital with a 50 kW unit. The school teacherages at New Bella Bella were provided with two 50 kW diesel generating units which were synchronized to run in parallel and which provided single phase, 120/240 V electrical power. The B.C. Packers system at East Bella Bella had been upgraded to one 25 kW diesel generator which provided 3-phase power at 240 V. Widsten Marine Services no longer retained the 20 kW Perkins diesel generator on standby. Millbanke Industries at Shearwater installed 50 kW and 75 kW diesel generators which provided 3-phase electrical power at 440 V. This power was distributed to the cannery and wharf during the operating season only.

In April 1969 a site investigation by B.C. Hydro and IPEC located a suitable site for a diesel generating station at Shearwater.[4] This location was selected because the station would be near tidewater and above any danger from tsunamis, there was available fresh water, a suitable substrate and the existing community was protected from noise by a natural slope. Heavy construction equipment and diesel mechanics were readily available. By 1970 two 500 kW Caterpillar generators had been installed by B.C. Hydro and a powerhouse had been constructed.

SECTION 2.0 - PLANT SITE SELECTION

For some alternative energy technologies the site is dictated by the location of the resources, whereas for other alternatives the plant may be sited in a favourable location which is selected for a number of other reasons.

The sites for hydroelectric, tidal and wind power tend to be site specific and governed by the availability of resources (Fig. B.1-1). The proposed small hydroelectric plant site is at Walker Lake on the mainland and approximately 18.5 km northeast of Shearwater. The proposed tidal site is at Hochstader Inlet on Campbell Island and approximately 10 km southwest of Bella Bella. The proposed wind site is on Mount Hand, approximately 4 km northwest of New Bella Bella; Mount Hand is more than 1000 feet (300 m) high and exposed to the predominant winds. Each of these sites is described in detail in the appropriate section of this report.

Thermal powerplants are sited based on the availability of fuel, cooling water and boiler make-up water as well as the location of the load and the dispersion characteristics of the air shed. For this preliminary study the site selected is on Campbell Island, northwest of Norman Morrison Bay. This site was selected for the following reasons:

1. The terrain is moderate.
2. The site is on the ocean which may be used as a source of cooling water and for docking facilities; coal or wood waste could be brought by barge.
3. Approximately 4.3 km of new distribution line would be required to connect this potential plant site to New Bella Bella.
4. The site is a considerable distance from residences on Campbell Island.
5. A nearby creek should provide sufficient water for boiler make-up.

Other thermal powerplant sites were examined at Defeat Point on Campbell Island and at Robins Point on Denny Island. These sites were not as attractive as Norman Morrison Bay for the reasons described above.

The sites for each of these alternatives were selected only for making cost estimates. A detailed site selection study would be required at an early stage of any subsequent study in order to define the most suitable site.

SECTION 3.0 - EXISTING FACILITIES

In March 1984 the facilities at Bella Bella consisted of the following diesel generating units (J.S. Wong, System Planning Department, B.C. Hydro, personal communication):

	kW
3 x 600 kW (Caterpillar D398 - stationary)	1800
2 x 600 kW (Caterpillar D398 - mobile)	1200
Total Generating Capacity	3000

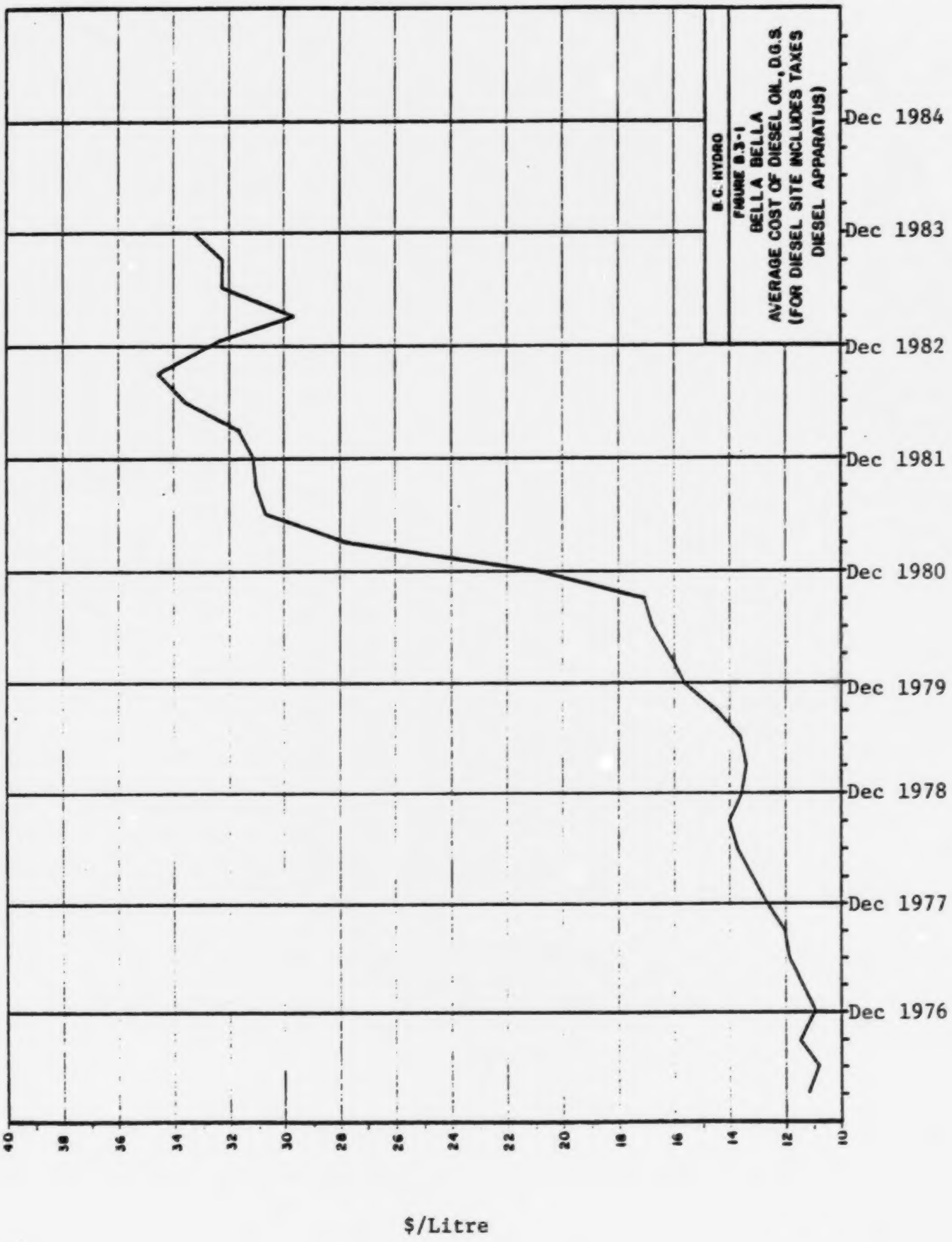
The firm capacity, with the largest diesel generating unit out of service is 2400 kW.

The diesel station is semi-automated and is operated and maintained by two operators. Fuel is delivered by barge from Vancouver and it is stored in vertical above ground storage tanks with a total capacity of 297 000 L.

The peak load for the Bella Bella diesel generating station in 1982/83, the last reporting year, was 1.80 MW (Diesel Apparatus Section, Monthly Report, March 1983) and the annual energy for 1982/83 was 7.74 GW·h. The station supplies electrical power to Shearwater and East Bella Bella on Denny Island, and to New Bella Bella on Campbell Island.

The primary distribution system from the generating station to the three communities is three phase and the secondary distribution to residential areas is single phase; both are at 25 kV (R.J. Meiner, Distribution Department, North Coast Division, B.C. Hydro, personal communication). In 1970 submarine cables were installed between Denny and Campbell islands. In December 1977 these cables were replaced after the original cables were cut by a barge which dragged its anchor during a storm. There are presently four submarine cables joining the two islands of which three are in service.

The cost of diesel generation increased dramatically during the 1970s and early 1980s because of the escalating cost of crude oil. The average quarterly costs of diesel fuel at Bella Bella are illustrated in Fig. B.3-1. The cost of diesel fuel increased abruptly beginning in September, 1980 and reached a peak of $0.345/L in September, 1982 (Diesel Apparatus Department, B.C. Hydro). The cost then fell abruptly to $0.296/L in September 1983 and it increased again to $0.333/L by December 1983. It is difficult to estimate a diesel fuel cost for this study because of the extreme volatility of the fuel cost over the last 3 years. This volatility has resulted from world demand for crude oil



B.C. HYDRO
FIGURE 8.3-1
BELLA BELLA
AVERAGE COST OF DIESEL OIL, D.G.S.
(FOR DIESEL SITE INCLUDES TAXES
DIESEL APPARATUS)

and Canada's National Energy Policy. However, it is expected that the cost of diesel fuel will remain constant in the near-term and then increase as economic recovery occurs. The December 1983 fuel cost has been used as the base cost of diesel fuel for this study.

The present load serviced by the B.C. Hydro generating station at Bella Bella is both residential and commercial. There are presently 357 customers (Diesel Apparatus Department, B.C. Hydro) in the Bella Bella area. Residential load is governed largely by the number of residents. The population statistics for the communities which are supplied by the Bella Bella generating station are as follows (Statistics Canada - 1981 Census):

New Bella Bella	659	(1300 estimated)
East Bella Bella	77	
Shearwater	23	
Total	759	(1400 estimated)

The Statistics Canada estimates of population appear to significantly underestimate the number of residents on Campbell Island compared to estimates obtained from the local people. The electrical load is high during the fishing season when the cannery is operating and during cold periods in the winter due to the prevalence of electric heat.

SECTION 4.0 - FUTURE POWER REQUIREMENTS

Projections of load requirements for 1982/83 to 1990/91 are estimated in Table B4-1. These estimates assume that there are no increases in industrial load and no substantial increases in residential load due to industrial development. The present growth rate would require that an additional 600 kW unit be installed in 1989/90 (J.S. Wong, System Planning Department, personal communication); additional diesel generation would be added as required. The proposed addition of a sawmill, improvements to the airstrip and the use of Shearwater as a base for oil exploration in Queen Charlotte Sound and Hecate Strait could increase the rate of growth significantly. Similarly, at New Bella Bella the proposed addition of 25 electrically heated homes, an ice plant, hotel and marina could also add appreciably to the electrical load.

An alternative to more diesel generation is to construct a 60 kV transmission line from Ocean Falls to Bella Bella. Ocean Falls has excess hydro capacity with 14 MW installed and a peak load of 3.8 MW.[5] Reid Crowthers and Partners have examined this alternative in a study which was jointly funded by the B.C. Cellulose Corporation and B.C. Hydro. This alternative is described in detail in Section 5.9 of this report.

TABLE B4-1

PROJECTION OF GROSS LOAD REQUIREMENTS AND LOAD GROWTH FOR BELLA BELLA[1]

	Peak	Energy
Actual Load 1982/83	1.80 MW	7.74 GW·h
Growth 1983/83 to 1990/91	4.5%	3.7%
Projected Load 1990/91	2.55 MW	10.35 GW·h

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[1] J.S. Wong, System Planning Department, B.C. Hydro, personal communication.

SECTION 5.0 - ENERGY RESOURCES AND SUPPLY

5.1 INTRODUCTION

The following subsections summarize the known energy sources which are available in the Bella Bella area and assess them as possible power sources for the B.C. Hydro system. These sources are diesel and alternative fuels, small hydroelectric, ocean wave, tidal, wind, wood waste, tree farms, peat, coal, municipal solid waste, geothermal and transmission.

5.2 DIESEL AND ALTERNATIVE FUELS

The present diesel plant is described in Section 3.0 of Part B and the potential for the use of alternative fuels is similar to that described in Section 5.2 of Part A. CNG and LNG would be excellent fuels, but the transportation, handling and storage would be difficult.

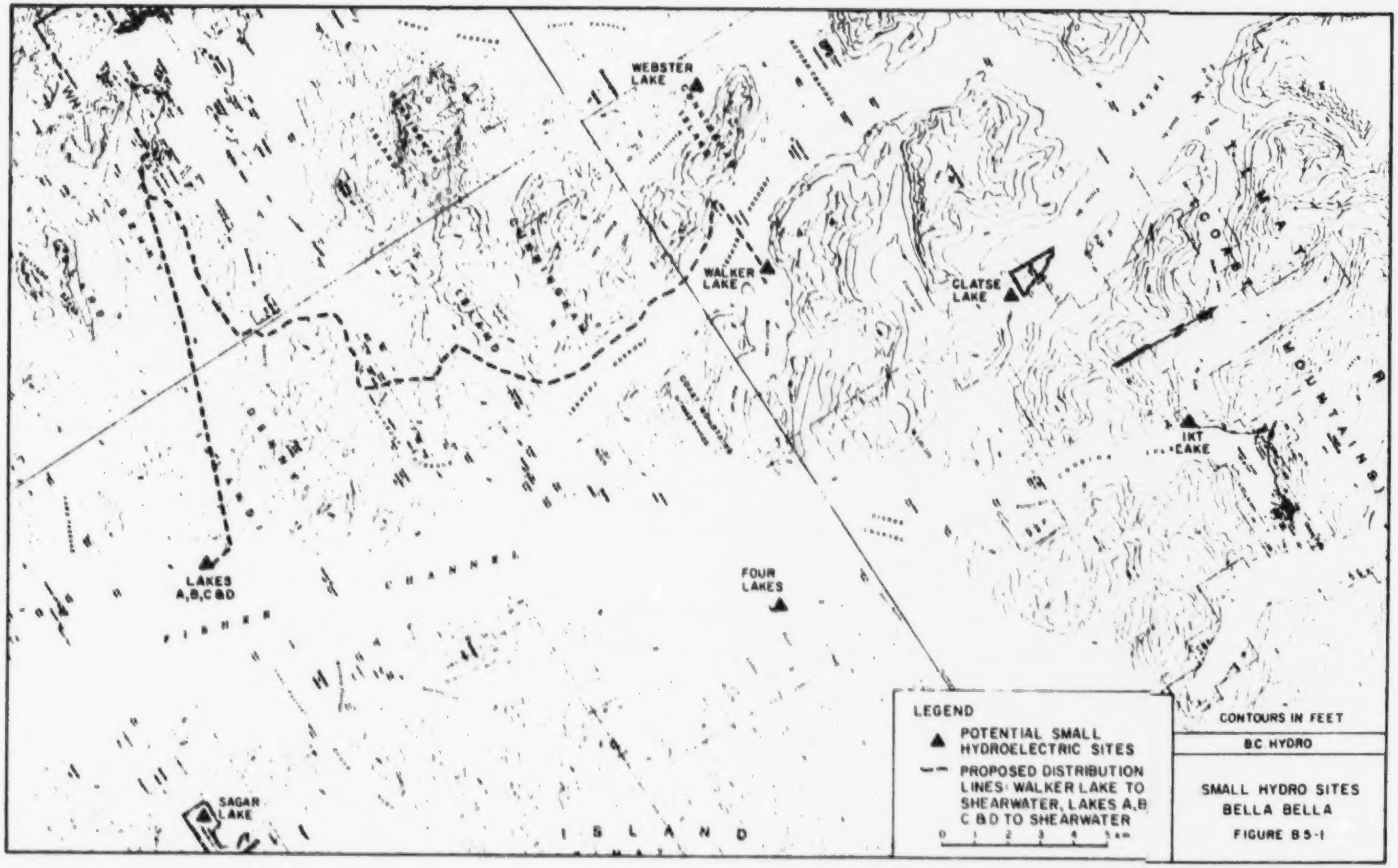
5.3 SMALL HYDROELECTRIC

(a) Introduction

Small hydroelectric technology is described in Appendix A. Following a map study, a field reconnaissance survey was made of the area within a 20 km radius of the Bella Bella community (Fig. B.5-1). Of the seven small hydroelectric sites identified in the map study, four potential sites (Four Lakes, Sagar Lake, Walker Lake and Webster Lake) were examined by helicopter; a ground survey was not possible due to time constraints, rugged terrain and dense vegetation cover. The purpose of the site survey was to determine the overall suitability for development, identify specific site features and determine environmental constraints.

An earlier B.C. Hydro study identified one potential site on Denny Island which was referred to as Lakes A, B, C and D.[2] Although this site was not visited during the course of this study, its close proximity only 13 km from the load centre makes it attractive.

Map studies were also conducted on two other sites, Clatse and Ikt lakes, which are more than 30 km from Bella Bella. The length of transmission line required would appear to preclude these sites from further consideration.


KITIMAT
COAST MOUNTAINS
R
WEBSTER LAKE
WALKER LAKE
CLATSE LAKE
IKT LAKE
FOUR LAKES
LAKES A,B,C&D
SAGAR LAKE
FISHER CHANNEL
ISLAND
LEGEND
▲ POTENTIAL SMALL HYDROELECTRIC SITES
PROPOSED DISTRIBUTION LINES: WALKER LAKE TO SHEARWATER, LAKES A,B C &D TO SHEARWATER
0 1 2 3 4 5 km
CONTOURS IN FEET
BC HYDRO

SMALL HYDRO SITES
BELLA BELLA
FIGURE B5-1

(b) Potential Sites

(i) Walker Lake

The Walker Lake catchment basin is 18.5 km² (Fig. B.5-2) in size and consists of a 3.6 km² lake at El. 75 m surrounded by steep terrain rising to 850 m.

A powerhouse site could be located on the creek flowing from Walker Lake, where it discharges into Johnson Channel. The site would require a 27 km overhead distribution line and a 1.5 km underwater crossing to connect to Bella Bella .

There are small salmon runs on the lower part of the creek draining from Walker Lake.[6] A 12 m falls approximately 400 m from the mouth blocks any further migration of salmon.

(ii) Webster Lake

This catchment basin is 25.4 km² and contains a lake system of about 5.5 km², one of the largest in the area. The lake, which is at an El. 50 m, is surrounded by very precipitous terrain rising to a height of 750 m. The westerly aspect of the high precipitous slopes will likely result in fast runoffs and higher flows than precipitation data would indicate.

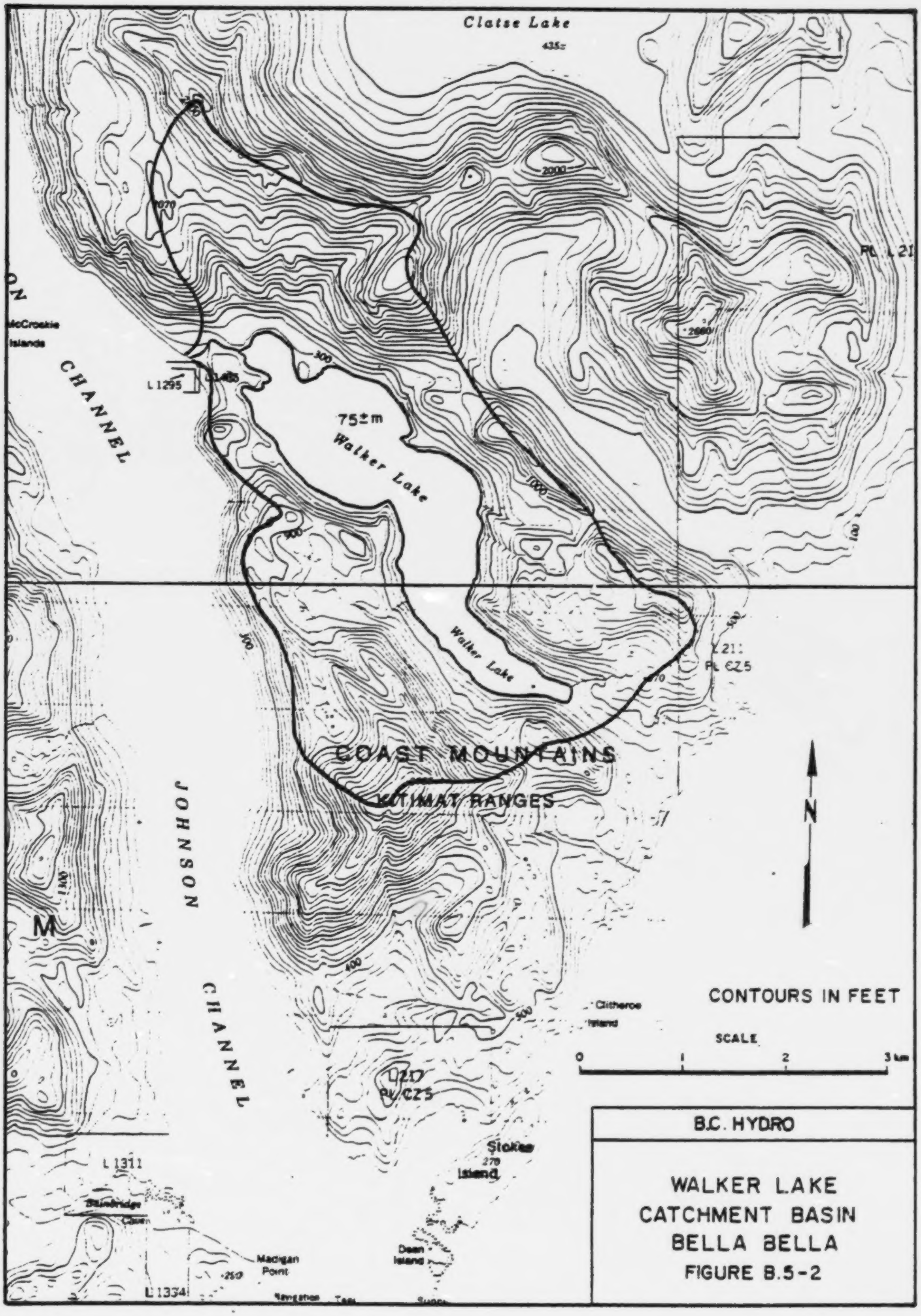
A powerhouse site could be located on the unnamed creek flowing from Webster Lake where it discharges into Troup Passage. The distribution line distance to Bella Bella would be approximately 24 km and would be routed across the central part of Cunningham Island, with a short aerial or submarine cable crossing of Gunboat Passage.

There is a small salmon run in the lower 1 km of the creek draining Webster Lake.[6]

(iii) Four Lakes

The catchment basin is located on King Island and with an area of almost 59 km², the basin is the largest in the area. The principal feature of the basin is the group of four interconnected lakes with a single stream discharging from the lowest lake at an El. 20 m. Because of the large catchment area the flow is estimated to be the largest of all the basins examined, but the low available head severely limits the energy potential of this development.

A powerhouse site could be located at the mouth of the outlet creek from the lower lake where it discharges into Fisher Channel. The length of distribution line to Bella Bella is at


Clatse Lake
435±
2000
2660
1070
McCroskie Islands
CHANNEL
L 1295
L1485
300
75±m
Walker Lake
1000
900
Walker Lake
L211
PL CZ5
1070
COAST MOUNTAINS
KITIMAT RANGES
N
JOHNSON CHANNEL
M
400
500
Clitheroe Island
L217
PL CZ5
Stokes Island
270
L 1311
Bainbridge Cove
Madigan Point
250
Dean Island
L 1334
CONTOURS IN FEET
SCALE
0
1
2
3 km

B.C. HYDRO

WALKER LAKE
CATCHMENT BASIN
BELLA BELLA
FIGURE B.5-2

least 24 km and distribution would entail a submarine crossing of approximately 2 km to reach Denny Island.

The lakes and their associated outlet creeks are believed to be salmon spawning areas. Environmental constraints could limit development.[6]

(iv) Sagar Lake

This catchment basin is 36 km^2 in area and it is near the southern end of King Island. A creek 2 km long provides for the natural outflow from Sagar Lake. Sagar Lake is 9.2 km^2 in area and the lake is at El. 43 m.

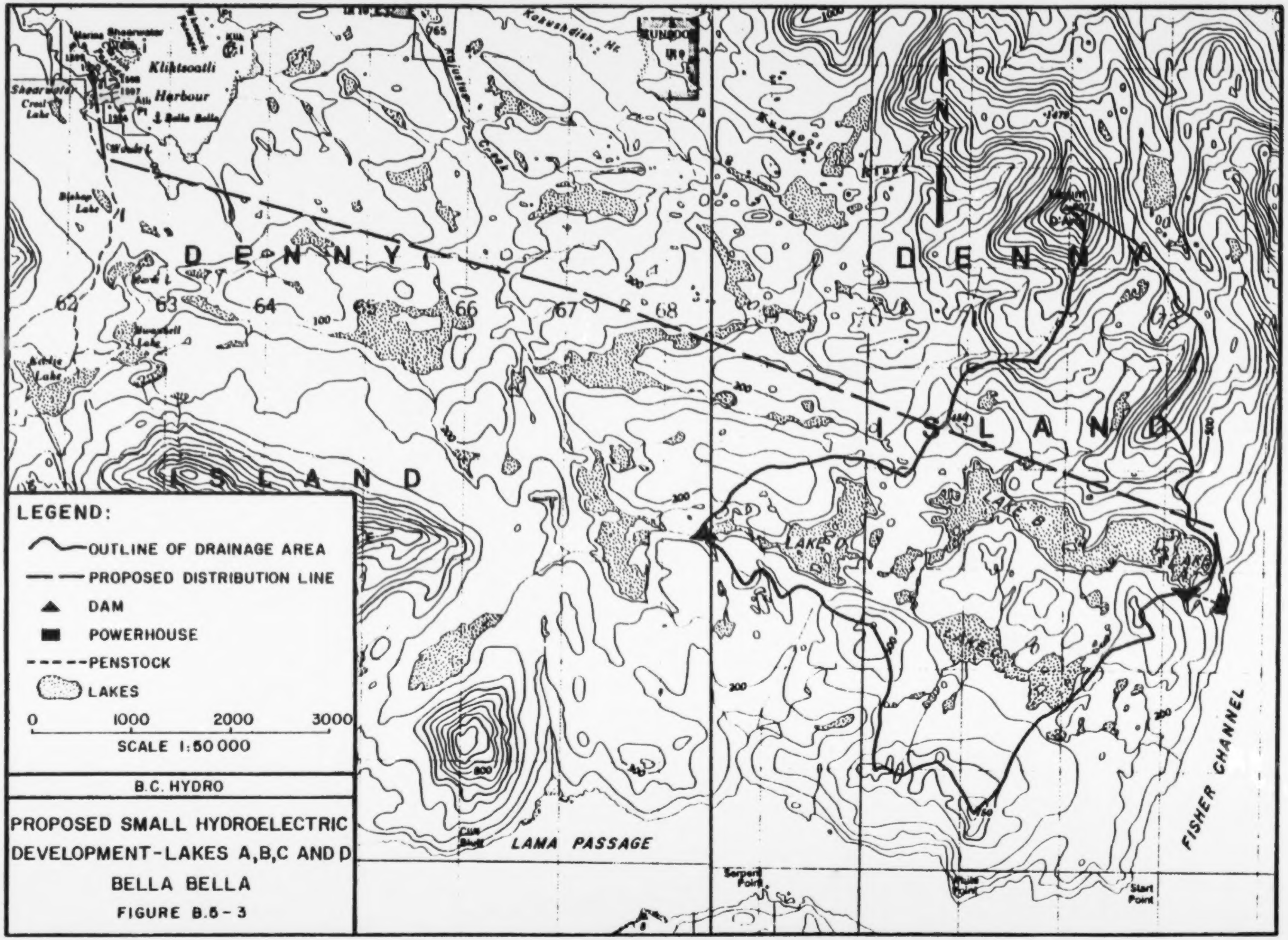
The existing creek flowing from Sagar Lake does not appear to be suitable for power development, but a low and narrow shelf of land at the southern end of the lake could provide a potential site. Development would require damming of the outlet from the lake and diverting the lake outflow into Codville Lagoon via a tunnel, canal and/or penstock. Connection to Bella Bella would require a 17 km of distribution line with 3 km of submarine cable across Fisher Channel to Denny Island.

The southern end of the lake and the general area of the potential site, including Codville Lagoon, is in a provincial park. Any development could conflict with recreational interests.

(v) Lakes A, B, C, D (Denny Island)

On 29 May, 1963 Mr. W.W. Chow of B.C. Hydro examined the potential of four unnamed lakes on Denny Island, designated A, B, C and D, for potential small hydroelectric development.[2] The potential site for small hydroelectric development is approximately 13 km east of Shearwater. The area consists of gently rolling hills, but there is a steep gradient from Lake A (El. 54 m) to the sea. Lakes A, B and C presently drain in this direction, whereas Lake D appears to drain toward Kakushdish Harbor.

It could be possible to develop the hydroelectric potential of this site with a powerhouse located at sea level at the mouth of the creek flowing from Lake A. The 1963 survey identified the potential for increasing the annual flow by damming the outlet of Lake D and diverting Lake D into the drainage area of Lake B. The total catchment area of Lakes A, B, C and D would be 14 km^2 (Fig. B.5-3). A distribution line approximately 14 km long would be required to connect the site to Shearwater.


LEGEND:
OUTLINE OF DRAINAGE AREA
PROPOSED DISTRIBUTION LINE
▲ DAM
■ POWERHOUSE
PENSTOCK
LAKES
0
1000
2000
3000
SCALE 1:50 000
B.C. HYDRO
DENNY ISLAND
DENNY ISLAND
LAKE A
LAKE B
LAKE C
LAKE D
LAMA PASSAGE
FISHER CHANNEL
Klihtsoatli
Harbour
Bella Bella
Shearwater
Kakushdish Hr.
Creek
Serpent Point
Start Point
62
63
64
65
66
67
68
100
200
300
800
1479

PROPOSED SMALL HYDROELECTRIC DEVELOPMENT-LAKES A,B,C AND D BELLA BELLA

FIGURE B.5-3

Kajusdus Creek which flows from Lake D to Kakushdish Harbor is an important salmon spawning stream.[6] However, the drainage area of Lake D is only a small part of the drainage area for Kajusdus Creek and at this stage of assessment the impact of diverting the drainage is unknown.

(vi) Ikt Lake

This catchment basin is 35 km² in area and consists of Mokst Lake at an El. 35 m which flows into Ikt Lake which is at El. 29 m.

A potential powerhouse site is located on the creek flowing from Ikt Lake where it discharges into Cousins Inlet. The site lies on the Ocean Falls coastal road about 5 km from the community, but the site is more than 40 km from Bella Bella.

Map studies indicate that the site does not offer any particular benefit over other sites closer to Bella Bella.

(vii) Clatse Lake

This catchment basin is 20 km² in size and consists of two interconnected lakes at Els. 132 and 130 m respectively. The elevations of the lakes and the catchment area are the highest of those considered. The lake is surrounded by terrain which rises to more than 1200 m.

A powerhouse site could be located on the creek flowing from the lower lake and could utilize 70 m of fall through a section of rapids. Because the location lies well inland a 6 km road would be required to provide site access and a transmission corridor to the coast at Wearing Point. The site is only 10 km from Ocean Falls and more than 37 km from Bella Bella. The long transmission distance and submarine crossings would be costly and difficult.

Although the site appears to be technically feasible it does not offer any particular advantage over other closer sites.

(c) Site Selection

Within the limits of the available information all of the sites appear to be technically feasible, but more detailed ground survey work would be required to confirm this preliminary assessment.

Each of the sites is associated with an elevated lake system which is drained by a single short and steep outlet stream. The principal site features are summarized in Table B5-1 which shows that, due to a combination of head and flow values, the energy potentials of most of the sites are of the same order of magnitude.

TABLE B5-1

HYDROELECTRIC SITE SUMMARY - BELLA BELLA

Basin	Installed Capacity (kW)	Potential Energy (GW·h)	Drainage Area (km²)	Annual Flow (m³/s)	Available Head (m)	Available Storage ($m^3 \times 10^6$)	Storage to Annual Flow (percent)	Distribution	
								Land (km)	Sea (km)
Clatse Lake	1100	7.7	20	1.6	70	9.0	18	35	2
Four Lakes	960	6.7	59	4.8	20	8.1	5	24	2
Ikt Lake	780	5.5	35	2.8	29	3.6	4	38	2
Lakes A,B,C,D	500	3.5	14	1.2	54	0.4	1	14	0
Sagar Lake	1220	8.6	36	2.9	43	12.6	14	17	3
Walker Lake	1100	7.7	18	1.5	75	10.5	22	27	1.5
Webster Lake	970	6.8	25	2.0	50	14.7	23	24	0

Flow regulation through water storage would greatly increase firm generation because of the relatively small size of the catchment basins.

The ranking of sites is determined primarily on the basis of cost and environmental constraints. It can be assumed that those sites with the higher available heads and shorter transmission distances would be more economical to develop.

Such sites as Clatse Lake, Four Lakes and Ikt Lake which have a number of cost disadvantages would not appear to be good prospects for development to serve Bella Bella. Sagar Lake which has the highest potential energy of all the sites examined appears to be technically feasible. However, transmission would require up to 3 km of submarine cable and its location within a provincial park could impose environmental and recreational constraints.

The three remaining sites, Walker Lake, Lakes A, B, C and D, and Webster Lake, are the closest to Bella Bella and would require a minimum or no submarine cable. All three sites have good storage potential, moderately high heads and appear to be suitable for development. However, Walker Lake has more available head and greater energy potential and is likely to be a more cost effective site to develop. Lakes A, B, C and D, and Webster Lake have salmon runs which could conflict with any power development.[6] The Lakes A, B, C and D project would be only half of the potential installed capacity of Walker Lake, but it is on Denny Island only 13 km from Shearwater. The short length of distribution line (14 km) could make this a cost effective site.

Therefore, on the basis of these considerations, Walker Lake and Lakes A, B, C and D are examined further for potential small hydroelectric development(s).

(d) Development Concept - Walker Lake

(i) Site Description

The proposed site is located at the western end of Walker Lake where it discharges into Johnson Channel (Fig. B.5-1). The creek draining from Walker Lake is narrow and descends from an elevation of 75 m to sea level in a distance of approximately 850 m.

(ii) Hydrology

The source of the inflow into Walker Lake is a catchment basin of approximately 18 km^2. Due to its small size and the steepness of the surrounding terrain, runoff is likely to be rapid. Stream flow data is not available and the mean annual flow has been estimated from precipitation records at Bella

Bella. On the basis of 2672 mm annual precipitation,[7] runoff has been estimated to be in the order of 0.083 $m^3/s/km^2$, which compares favourably with other similarly exposed coastal basins. No allowance has been made for specific local conditions such as elevation which could increase "runoff" or interception factors which could reduce it.

The mean annual flow from Walker Lake is estimated to be about 1.5 m^3/s and flows are likely to be at a minimum during the summer months due to the precipitation pattern for the area and the lack of snow pack.

(iii) Power Studies

Because of the small size of the catchment basin and the seasonal precipitation pattern, flow regulation would be required to ensure that the energy potential of the basin would be fully utilized and that generation would not be interrupted. A small weir-type dam would have to be built across the outlet of the lake to regulate flow and provide storage capacity. It is estimated that a 3 m change in the lake level would provide $10.5 \times 10^6 m^3$ of storage, representing 22 percent of the mean annual flow.

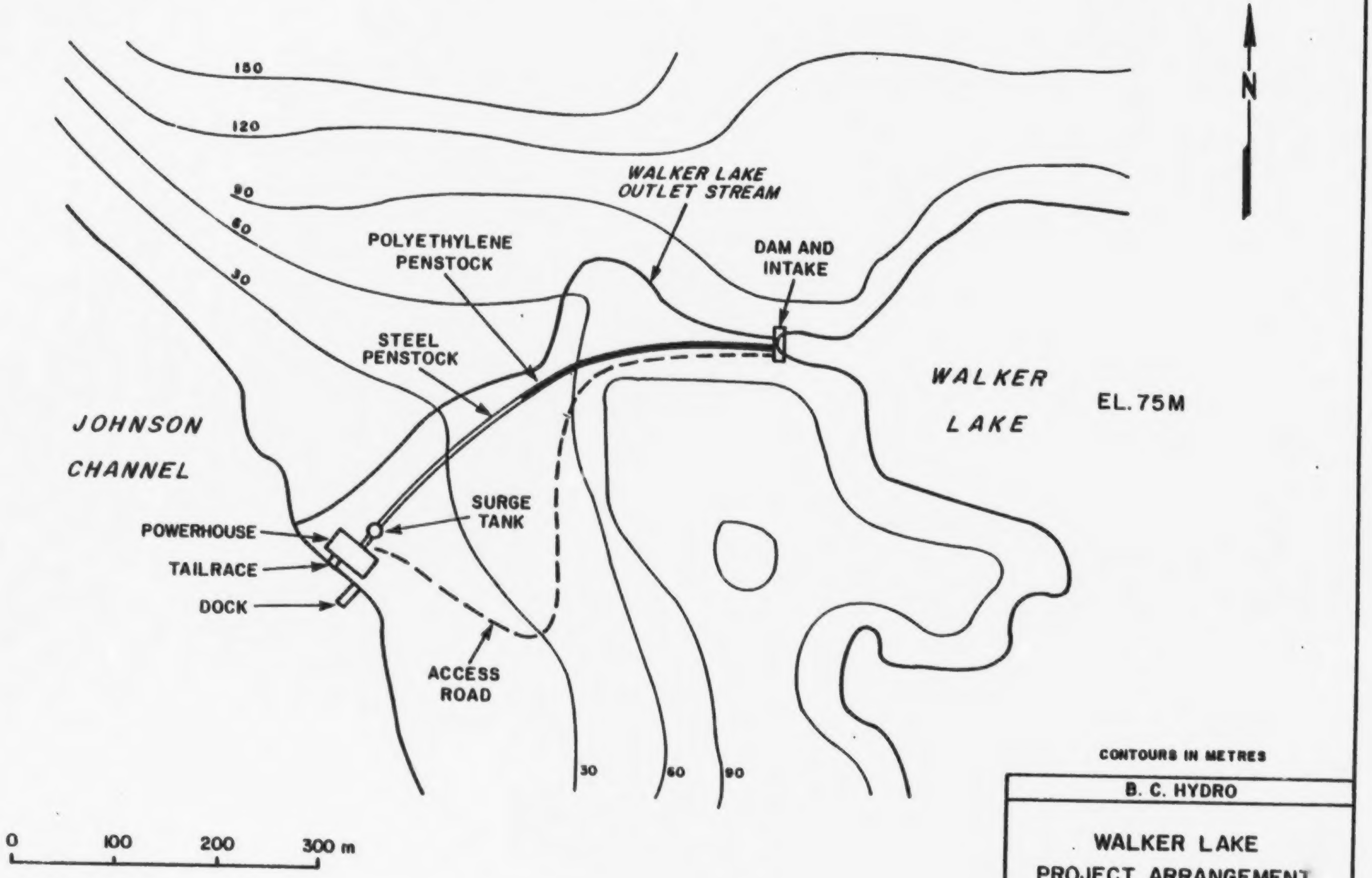
On the basis of the estimated mean annual flow of 1.5 m^3/s and a gross head of 75 m, the estimated average annual energy of this site is approximately 7.7 GW·h. Assuming a plant capacity factor of 80 percent the installed capacity would be in the order of 1100 kW.

It is estimated that load growth in the Bella Bella area will result in a peak demand of 2.55 MW in 1990/91 and an energy consumption of 10.36 GW·h. It is evident that the development of the Walker Lake site by itself could meet only 42 percent of the peak demand and 74 percent of the energy requirements.

(iv) Project Arrangement

The recommended layout of the project is described in this subsection, but more detailed study would be required to determine the final dimensions and the optimum location of principal structures (Fig. B.5-4). The project would include the following structures:

1. A water intake structure would be constructed at the lake outflow (El. 75 m) and designed to regulate flow and draw water from the lake. Subject to more detailed studies the structure may be designed to provide limited storage on the lake and/or provide for drawdown. It is estimated that full storage potential would permit operation of the plant for a period of 2 months at the rated capacity of


N
150
120
90
60
30
WALKER LAKE OUTLET STREAM
POLYETHYLENE PENSTOCK
DAM AND INTAKE
STEEL PENSTOCK
WALKER LAKE
EL. 75M
JOHNSON CHANNEL
SURGE TANK
POWERHOUSE
TAILRACE
DOCK
ACCESS ROAD
30
60
90
CONTOURS IN METRES
0
100
200
300 m

B. C. HYDRO

WALKER LAKE
PROJECT ARRANGEMENT
FIGURE B.5-4

1100 kW. The intake structure and dam would require trash racks to avoid blockage due to floating debris or ice and provision would be needed for discharges in the event of a flood.

2. A polyethylene penstock of approximately 900 mm diameter and 600 m in length would be laid above ground on a bed of sand or buried at a shallow depth. The lower part of the penstock would likely be steel.

3. A closed surge tank would be located adjacent to the powerhouse.

4. A steel-framed powerhouse with a single 1100 kW capacity turbine/generator unit would be constructed at the lower end of the penstock.

5. A transformer to step up voltage from 2400 V to 25 kV would be constructed.

6. A 27 km overland distribution line would be constructed from the site to the existing B.C. Hydro switchyard at Bella Bella (Shearwater). The line would follow the coast in part to provide ease of access (Fig. B.5-1). A 1.5 km submarine cable would be required to cross the Johnson Channel and an aerial crossing would be required at Gun Boat Passage.

(e) Development Concept - Lakes A, B, C and D

(i) Site Description

The proposed site is located on the west side of Denny Island (Fig. B.5-1) where the outlet creek of Lake A flows into Fisher Channel. The creek falls from an elevation of 54 m to sea level in a distance of approximately 400 m (Fig. B.5-3).

(ii) Hydrology

The rainfall runoff ratios were developed from precipitation records at Bella Bella[7] and are estimated to be in the order of 0.083 $m^3/s/km^2$.

The mean annual flow from Lakes A, B, C and D is estimated to be approximately 1.2 m^3/s with the yearly distribution similar to that assumed for Walker Lake.

(iii) Power Studies

The potential for storage which would improve regulation for this project is small. The intake would be on Lake A and the area of this lake is approximately 0.125 x $10^6 m^2$. If it is assumed that live storage of 3 m could be made available on Lake A this would provide 0.375 x $10^6 m^3$ of storage, representing 1 percent of the mean annual flow.

On the basis of the estimated mean annual flow of 1.2 m^3/s and a gross head of 54 m the estimated average annual energy of this site is approximately 3.5 GW·h. Assuming a plant capacity factor of 80 percent the recommended installed capacity would be in the order of 500 kW.

(iv) Project Arrangement

The layout for Lakes A, B, C and D is assumed to be similar to that shown for Walker Lake (Fig. B.5-4). This site was not visited during the course of this study and the available topography is not in sufficient detail to recommend a project layout.

A 14 km distribution line from the site to the existing B.C. Hydro switchyard at Shearwater would be required (Fig. B.5-3). The line is assumed to cross Denny Island more or less in a straight line. No channel crossings would be required.

(f) Environmental

Fishing and particularly salmon are a prime resource in the Bella Bella area. Most streams provide spawning and fish habitat and it is unlikely that development of either Walker Lake or Lakes A, B, C and D would be without an environmental impact.

At this time it is known that both Walker Lake and Lake D are on salmon spawning streams and further studies would be required to determine the impacts of small hydro development(s). The spilling of water and other selected costs for protecting the fisheries resource could make development of either of these small hydroelectric sites economically infeasible.

5.4 OCEAN WAVE

Measurements conducted by the National Research Council[8] in 1974 off Tofino indicated that the average power of waves in that area is about 35 kW/m of wave front (Appendix A). Bella Bella is less open to the ocean. Therefore, wave energy in the area is expected to be less than off Tofino, but there could still be a substantial resource.

To date there is no commercial method of extracting useful power from waves. However, many wave power technologies are under development.[9] Of these the dam-atoll[10] and oscillating water column[11] concepts appear to be promising (Appendix A). To capture sufficient energy both of these technologies envisage large structures which would be in the open ocean 1 to 2 km off the coast. Some of the aspects that impede the development and commercialization of wave energy technologies are the problems of mooring these large structures, transmission to shore, reliability of wave power devices, repair and maintenance in rough seas and environmental and navigational impacts.

Waves are strongest in the open ocean. Therefore, a wave power scheme for the Bella Bella area would ideally be located off the west coast of Athlone and Wurtle Islands. This would require about 30 km of transmission, including a few kilometres of submarine transmission. A wave power scheme would require extensive storage facilities because waves are not constant. More realistically, wave power may be applied in a fuel saving mode in areas of diesel electrical generation. A realistic cost estimate of wave power cannot be made because there is no commercially proven wave power technology. However, optimistic estimates of wave power are in the order of 10¢/kW·h;[9] therefore, it appears that there is some potential for wave power supplementing diesel power in the future.

5.5 TIDAL

(a) General

The islands near Bella Bella and Shearwater contain numerous inlets and channels which may be suitable for tidal power development.

Tidal currents in the waters near Bella Bella and Shearwater seem to be weak (i.e. less than 3 m/s), thus freestream tidal installations would not be practical. However, a number of local sites appear to have some potential for barrage-type development.

The mean tidal range at Bella Bella is 3.6 m[12], which is above the average for the B.C. Coast (Fig. AA4-2 in Appendix A), but it is still well below the range experienced in areas such as the Bay of Fundy where tidal power development appears feasible.

(b) Potential Tidal Sites

The locations of seven potential tidal sites in the Bella Bella/Shearwater area are shown on Fig. B.1-1. Basic technical data for these sites are summarized in Table B5-2. This information was compiled from a review of maps and marine charts, and from field reconnaissance in November 1983.

A preliminary cost parameter for each site is shown in Table B5-3. This parameter was estimated according to the procedure outlined in Appendix A. The data and other characteristics for each site are described below.

TABLE B5-2

BELLA BELLA - POTENTIAL TIDAL SITES
TECHNICAL DATA

Site	Tidal Range		Basin Area (km^2)	Channel Dimensions at Barrage Site		Distribution Distance (km)	Distribution Ranking
	Mean (m)	Extreme (m)		Length (km)	Mean Depth (m)		
1. Hochstader Basin	3.6	5.4	2.6	0.14	4.5	10	2
2. Campbell Island S.W.	3.6	5.4	0.7	0.11	4.5	12	3
3. Campbell Island S.E.	3.6	5.4	1.0	0.09	7.5	12	3
4. Kakushdish Harbour	3.6	5.4	0.6	0.11	5.5	5	1
5. Codville Lagoon	3.6	5.4	3.4	0.12	7.5	20 (4 km water crossing)	6
6. De Cosmos Lagoon	3.6	5.4	0.4	0.01	5.0	31 (1 km water crossing)	7
7. Lost Lagoon	3.6	5.4	1.0	0.10	7.5	16 (1 km water crossing)	5

TABLE B5-3

BELLA BELLA - POTENTIAL TIDAL SITES
CALCULATED PARAMETERS

Site	Energy Potential (GW·h/a)	Barrage Dimensions Length (km)	Barrage Dimensions Mean Height (m)	At-Site Energy Cost Parameter (km - m²/GW·h)	Cost Ranking
1. Hochstader Basin	13.1 (7 usable)	0.14	11.9	2.8	2
2. Campbell Island - S.W.	3.5	0.11	11.9	4.5	6
3. Campbell Island - S.E.	5.1	0.09	14.9	3.9	4
4. Kakushdish Harbour	3.0	0.11	12.9	6.1	7
5. Codville Lagoon	17.2 (7 usable)	0.12	14.9	3.8	3
6. De Cosmos Lagoon	2.0	0.01	12.4	0.8	1
7. Lost Lagoon	5.1	0.10	14.9	4.4	5

Notes:

1. Energy potential is calculated from the formula: $E = 0.39\ A\ R^2$ (GW·h/a) where A = basin area (km^2), R = mean tidal range (m) (see Appendix A, Section A.4).

2. Barrage mean height is determined from the sum:
(mean depth at low water) + (extreme tidal range) + (freeboard)
e.g. 5.4 m e.g. 2.0 m

3. Cost parameter is calculated from the formula: $CP = LH^2/E$ (km - m/GW·h) where L = length of barrage (km), H = mean tidal range (m), E = annual energy output (GW·h/a). (See Appendix A, Section A.4.)

(i) Hochstader Basin

Hochstader Basin is on the west side of Campbell Island, about 10 km from Bella Bella (Figs. B.5-5 and B.5-6). The entrance to the basin contains two small islands and the intervening channels appear suitable for construction of a barrage.

The energy potential of this site is estimated to be about 13 GW·h/a, which is somewhat larger than the demand projected for Bella Bella/Shearwater in 1990/91. The intermittent nature of tidal generation combined with daily load variations would indicate that tidal generation could not supply all of the local demand. It is estimated that the maximum amount of tidal generation which the local system could use would be approximately 7 GW·h/a.

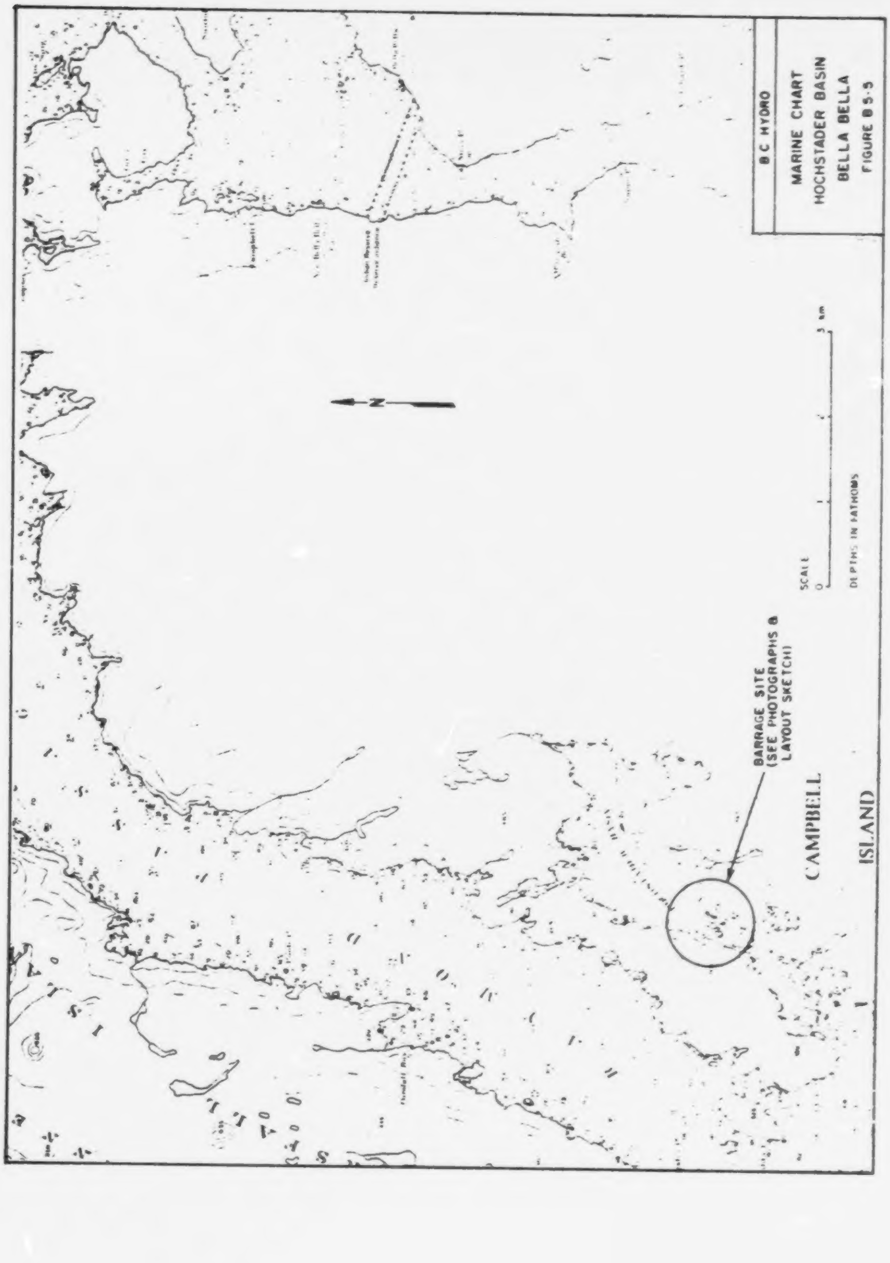
The technical data for Hochstader Basin suggests that there are no major technical constraints to the development of this site (Fig. B.5-7). The energy potential is large enough to make a significant contribution to the local system, and the basin entrance appears to have suitable characteristics for barrage construction (Figs. B.5-8 and B.5-9). The distance for distribution to Bella Bella is relatively short (10 km) and the terrain between the proposed tidal site on Hochstader Basin and Bella Bella is relatively flat and vegetation is sparse (Fig. B.5-6). Of the sites identified, Hochstader Basin ranks second in terms of the at-site energy cost parameter.

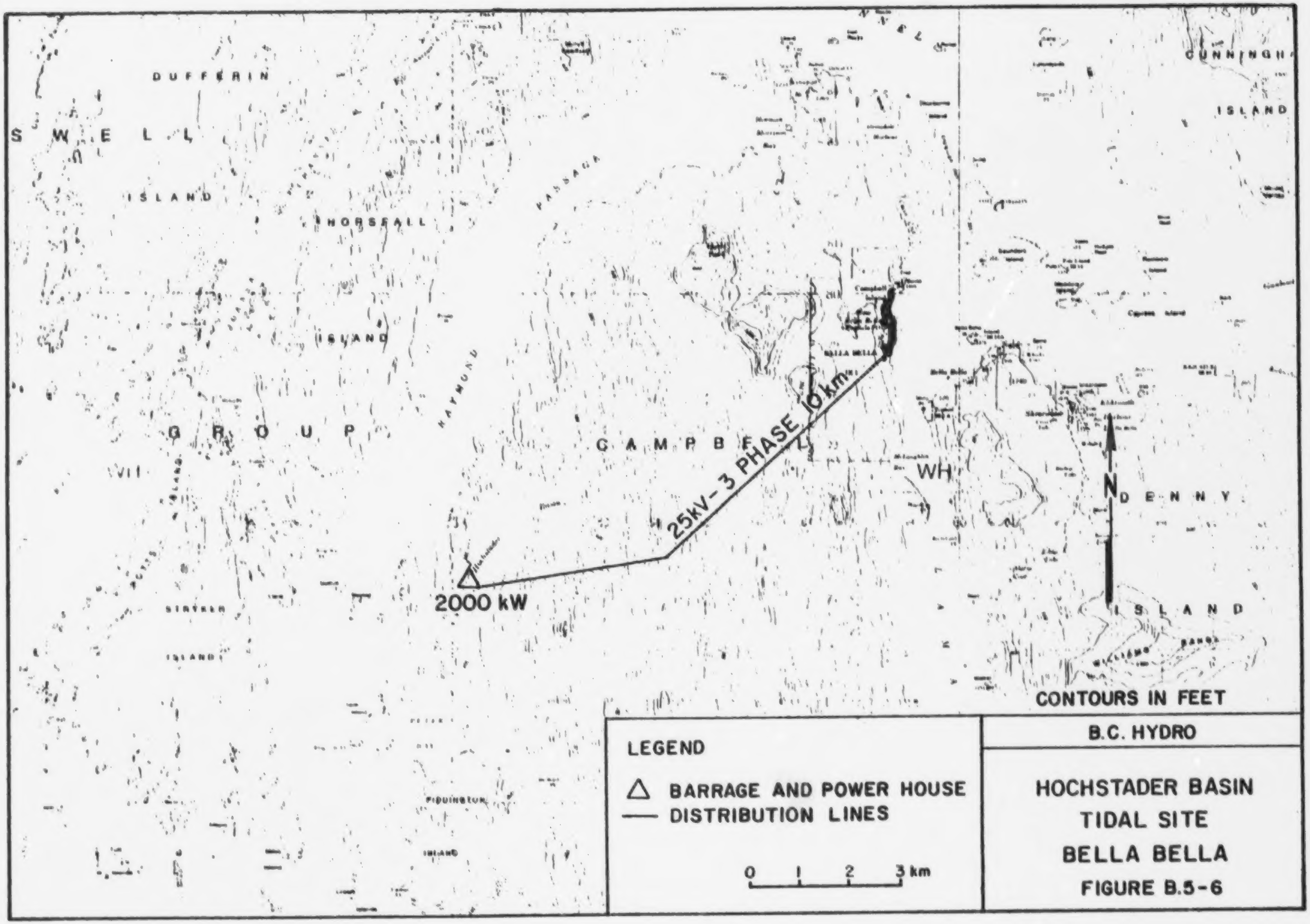
Environmental information from local residents and field reconnaissance indicates no apparent constraints to development. The basin appears to be little used as a boat anchorage, probably due to difficult navigation through the shallow, narrow entrance. There are no buildings on the perimeter of the basin. There appear to be no major streams suitable for fish spawning, thus salmon migration into the basin is probably insignificant. Some herring spawning is thought to occur in the basin, but numbers are expected to be small.

(ii) Campbell Island S.W.

The Campbell Island S.W. site is a long, narrow unnamed inlet on the southwest part of Campbell Island. A tidal barrage could be constructed across a narrows about 1.5 km from the entrance to the inlet. The energy potential of this site is estimated to be 3.5 GW·h/a, which is 35 percent of the projected energy demand for Bella Bella/Shearwater in 1990/91.

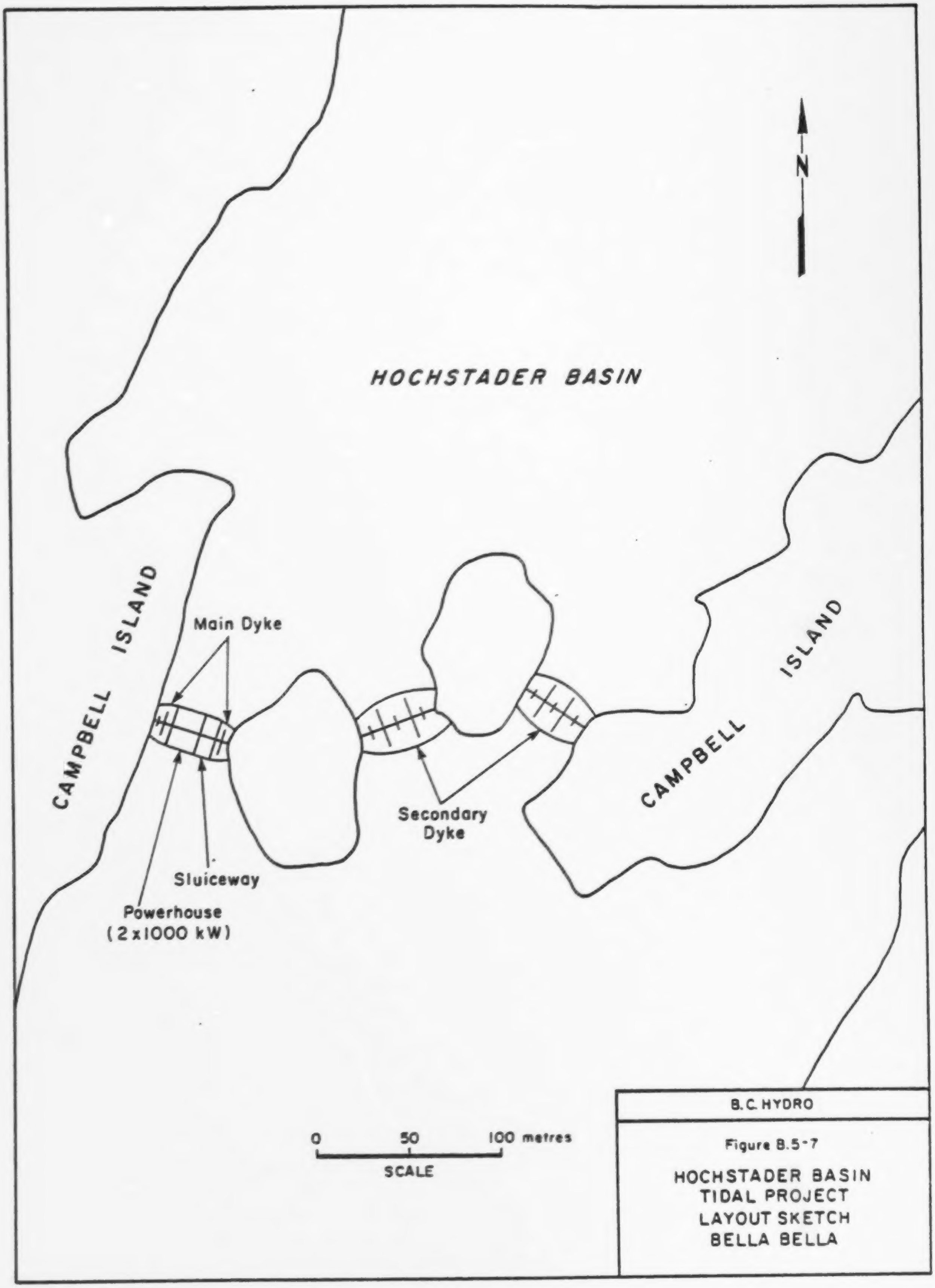
This site appears to have several technical and environmental complications which would discourage consideration for


B C HYDRO
MARINE CHART
HOCHSTADER BASIN
BELLA BELLA
FIGURE B5-5
N
SCALE
0
1
2
3 km
DEPTHS IN FATHOMS
BARRAGE SITE
(SEE PHOTOGRAPHS &
LAYOUT SKETCH)
CAMPBELL
ISLAND


DUFFERIN
SWELL
ISLAND
HORSEFALL
ISLAND
PASSAGE
RAYMOND
GROUP
CAMPBELL
CUNNINGHAM
ISLAND
DENNY
ISLAND
WH
N
25kV-3 PHASE 10km.
2000 kW
STRYKER
ISLAND
PIDDINGTON
ISLAND
BELLA BELLA
CONTOURS IN FEET
LEGEND
△ BARRAGE AND POWER HOUSE
— DISTRIBUTION LINES
0
1
2
3 km

B.C. HYDRO

HOCHSTADER BASIN
TIDAL SITE
BELLA BELLA
FIGURE B.5-6


N
HOCHSTADER BASIN
CAMPBELL ISLAND
Main Dyke
Sluiceway
Powerhouse (2 x 1000 kW)
Secondary Dyke
CAMPBELL ISLAND
0
50
100 metres
SCALE

B.C. HYDRO

Figure B.5-7

HOCHSTADER BASIN
TIDAL PROJECT
LAYOUT SKETCH
BELLA BELLA

FIGURE B.5-8 Barrage site at entrance to Hochstader Basin (looking north)

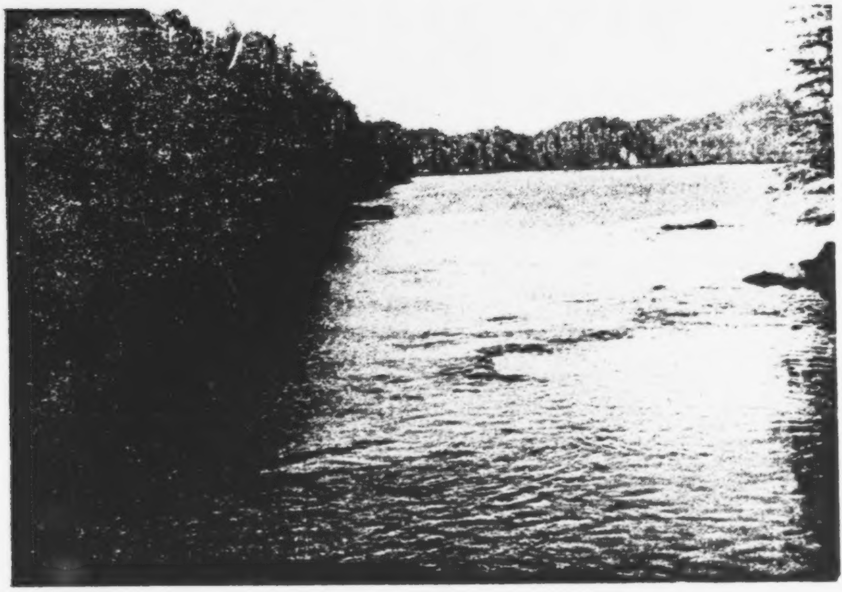


FIGURE B.5-9 Close-up of west entrance channel, proposed location of main dyke, sluiceway and power plant

development. Energy costs appear to be high in relation to other sites which have been identified (i.e. the site ranks sixth out of seven in terms of the at-site energy cost parameter). Also, it appears that excavation would be required at two constrictions upstream of the barrage site which would further increase the energy costs. Navigation into the inlet does not appear to be a concern, but local fisherman suggested that some salmon spawning is known to occur in the creeks draining into the head of the inlet. This spawning could be disrupted by a barrage development.

(iii) Campbell Island S.E.

The Campbell Island S.E. site is on the southeast side of Campbell Island and has similar characteristics to Campbell Island S.W. The energy potential is estimated to be 5.1 GW·h/a which is about 50 percent of the 1990/91 load demand.

Technical and environmental constraints to the development of this site would be similar to Campbell Island S.W. The at-site energy cost parameter ranks fourth among the seven identified sites. However, costs would likely be higher since it appears that excavation would be required at a constriction about 1.5 km up the inlet from the barrage site. Navigation into the inlet does not appear to be a concern, but disruption of fish migrations could be a problem (i.e. both salmon and herring are known to migrate into the inlet to spawn).

(iv) Kakushdish Harbour

Kakushdish Harbour is on Denny Island about 4 km east of Shearwater. A tidal barrage could be constructed across the shallows near the entrance to the inlet. The energy potential of the site is estimated to be 3.0 GW·h/a, which is about 30 percent of the forecast 1990/91 load demand.

This site ranks last in terms of the at-site energy cost parameter, although it would have the shortest distribution distance. Field reconnaissance indicates there would likely be several environmental complications in developing this site. Several creeks drain into the head of the inlet which likely provide salmon spawning habitat. In addition, there is an Indian reserve and several buildings at the head of the inlet. Water access to the reserve would be disrupted by a barrage development. Kakushdish Harbour also appears to provide good sheltered anchorage, although no boats or moorage facilities were observed.

(v) Codville Lagoon

Codville Lagoon is on the west side of King Island about 19 km southeast of Shearwater. A tidal barrage could be constructed across the relatively narrow entrance to the lagoon. The energy potential of this site is estimated to be 17.2 GW·h/a, although only about 7 GW·h/a of this potential could be utilized for the reasons described above (see Hochstader Basin).

Codville Lagoon ranks third in terms of the at-site energy cost parameter, but ranks next to last in terms of distribution distance (20 km). The distribution line would be a major constraint since a 4 km water crossing of Fisher Channel would be required. The lagoon provides water access to Sagar Lake Provincial Park which is a popular local summer recreation area, and a barrage would complicate access to this area. Salmon spawning is known to occur in the stream draining into the northern end of Codville Lagoon. Migration to and from this spawning area could be disrupted by a barrage.

(vi) De Cosmos Lagoon

De Cosmos Lagoon is located on the east side of Hunter Island about 25 km south of Shearwater. The entrance to the lagoon is very narrow and shallow, and exhibits a substantial tidal current, probably approaching 3 m/s. The site could be developed by construction of a small barrage across these narrows. Alternatively, consideration could be given to installation of a freestream unit. The energy potential of a barrage development is estimated to be 2.0 GW·h/a, which is the smallest energy potential of the seven sites. This potential is equivalent to about 20 percent of the forecast 1990/91 load demand.

Because of the very small barrage required, De Cosmos Lagoon ranks first in terms of the at-site energy cost parameter. However, it ranks last in terms of distribution distance (31 km with a 1 km water crossing) and about 10 km of the distribution line route on Hunter Island would be over rugged terrain. Navigation in and out of the lagoon is probably not a significant concern due the narrow channel and strong currents at the entrance which would discourage boat traffic. No specific information was obtained on fish resources, but some salmon spawning may occur in a small creek which discharges into the north end of the lagoon.

The limited energy potential and long distribution distance would appear to represent major constraints to the development of this site.

(vii) Lost Lagoon

Lost Lagoon is located on the west side of Cunningham Island about 10 km northeast of Shearwater. The entrance to the lagoon appears to be a suitable site for a tidal barrage. The energy potential of the site is estimated to be 5.1 GW·h/a which is about 50 percent of the forecast load demand for the area in 1990/91.

Lost Lagoon ranks fifth in terms of the at-site energy cost parameter and fifth in terms of the length of distribution line. The distribution would involve a 1 km water crossing. A lake and stream system which drains into the north end of Lost Lagoon, appears to be important salmon spawning habitat.

Neither the technical nor environmental factors appear favourable for development of this site.

(c) Preferred Site

The above descriptions indicate that Hochstader Basin would be the preferred site for tidal development near Bella Bella. The main advantages of this site are summarized as follows:

Technical Factors

1. The energy potential is comparable to the load demand in the Bella Bella area.
2. The length of distribution line is relatively short (10 km).
3. The at-site energy cost parameter is lower than all other sites except De Cosmos Lagoon (rejected due to limited potential and long distribution line required).

Environmental Factors

1. Navigation in and out of Hochstader Basin appears negligible.
2. No significant salmon spawning is known to occur in streams flowing into Hochstader Basin.

5.6 WIND - BELLA BELLA

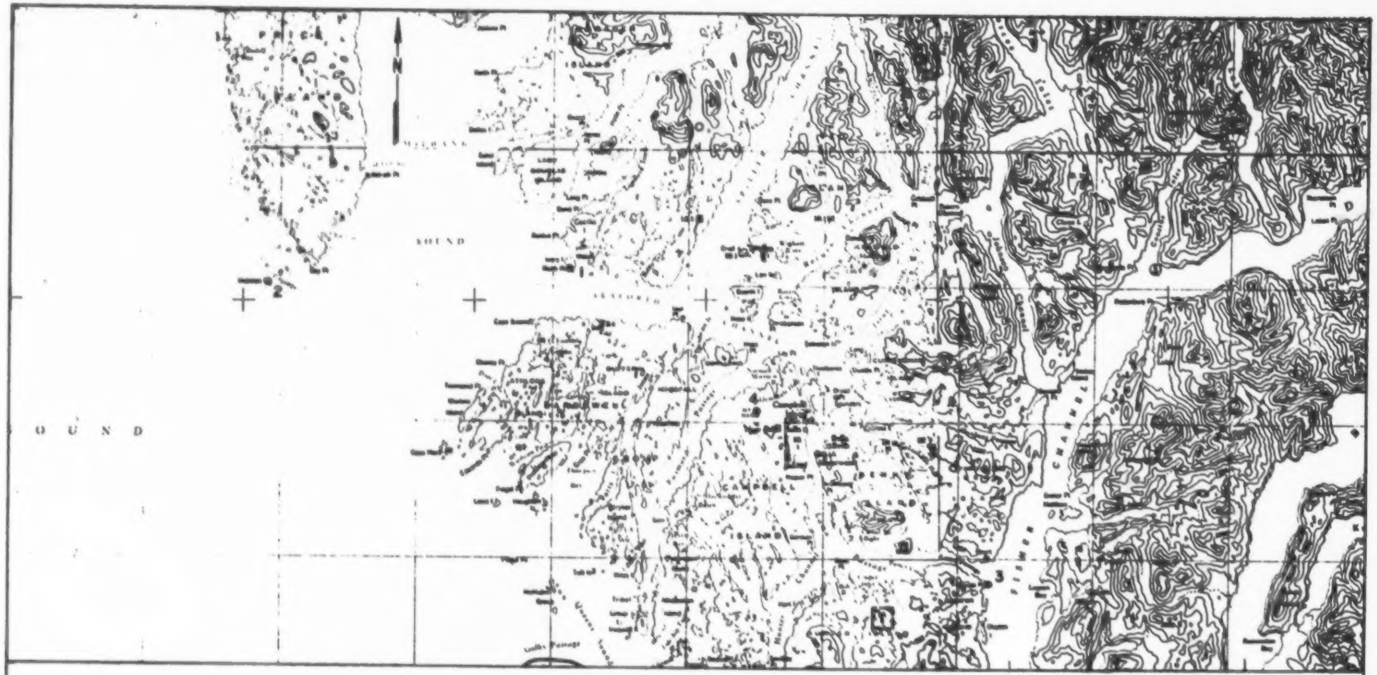
Wind is a renewable energy source which could be harnessed by wind turbines in order to produce electrical energy. However, power from wind could be considered only as a supplementary source because of its variable and unpredictable nature. Thus, wind turbines could be installed in the vicinity of Bella Bella as a diesel fuel saver. The amount of fuel that could be saved by wind generation at any location is dependent on the installed capacity of the wind turbines and on the wind regime. Generally, it is considered that the optimum capacity of the allowable wind component should be about equal to the minimum demand of the system. Such an installation could save up to 20 percent of the diesel fuel depending on the wind regime.[13]

The average wind speed at McInnes Island is 5.86 m/s (21.1 km/h) based on data collected by the Atmospheric Environment Service (1958 to 1974, Fig. B.5-10).[14] There are no B.C. Hydro wind monitoring sites in the Bella Bella area. For estimating the energy capability it is assumed that wind turbines would be installed on Mount Hand (El. 300 m), and that the average wind speed at this site is 6 m/s (21.6 km/h). Mount Hand is a high site and exposed to the open ocean and it is assumed that the wind regime is similar to McInnes Island (Fig. B.5-11). A logging road provides access to the top of the mountain (Fig. B.5-13). The 6 m/s average wind speed is the speed at which the wind machines are rated as per the American Wind Association (AWEA) draft performance rating standard.[13] The Williams Range on Denny Island could provide an alternate site if Mount Hand proved to be unsuitable (Fig. B.5-12, B.5-13).

The projected peak demand for Bella Bella in 1990/91 is 2.55 MW and the projected annual energy consumption is 10.35 GW·h. Assuming a 30 percent minimum load/peak demand ratio, the minimum load would be 780 kW in 1990/91. In order to meet this load 4 x 200 kW Horizontal Axis Wind Turbines were selected. On the basis of the AWEA draft performance standard this HAWT has a capacity factor of 32 percent at an average wind speed of 6 m/s. At this capacity factor the estimated cost of power from the wind is 18.8¢/kW·h (1983$). Four 200 kW turbines could generate about 2.26 GH·h which could result approximately in a 22 percent fuel saving.

Ultimately, the output of different machines for the existing wind regime must be compared in order to obtain a better estimate of energy costs for wind. Wind data pertaining to the particular location is necessary to do such an analysis. In this respect it would be desirable to monitor wind speeds on Mount Hand if wind was considered a viable alternative for Bella Bella.

There are no significant environmental impacts from wind generation. The principal impact is expected to be the land use conflicts. Assuming a rotor diameter of 24 m and an allowance of 10 rotor diameters/turbine, approximately 18 ha would be required for an 800 kW wind farm on Mount Hand.


N
SOUND
O U N D
2
3

LEGEND

MONITORING SITES

1. IVORY ISLAND
2. McINNES ISLAND
3. POINTER ISLAND (KAIETE POINT)

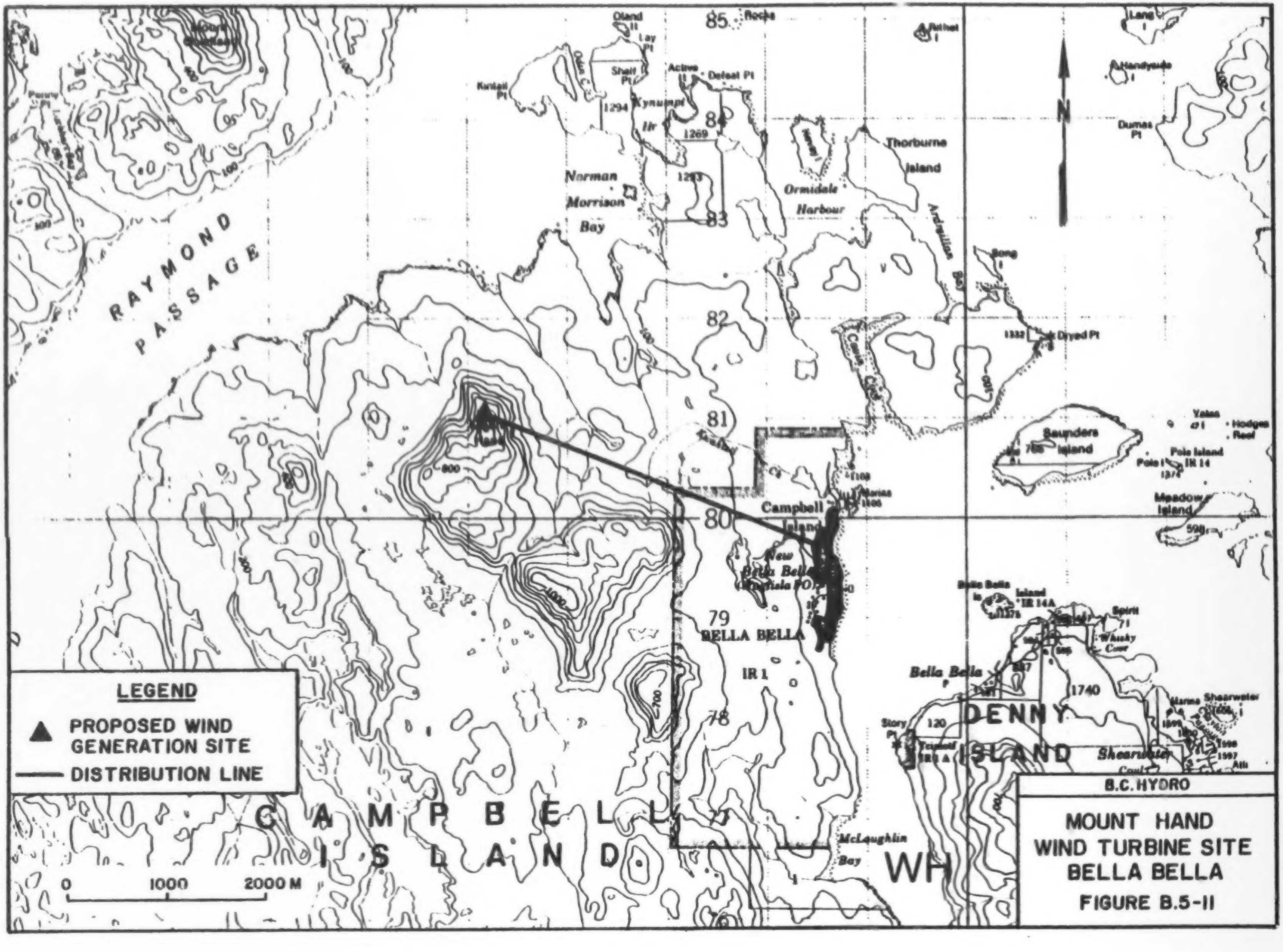
WIND TURBINE SITE

4. MOUNT HAND

0
5
10
15
kilometres

B C HYDRO

FIGURE B 3-10
WIND MONITORING AND TURBINE SITES
BELLA BELLA, B.C.



RAYMOND PASSAGE
Norman Morrison Bay
Kynumpt Hr
Ormidale Harbour
Thorburne Island
Ardmillan Bay
Campbell Island
New Bella Bella
BELLA BELLA
IR 1
McLoughlin Bay
Bella Bella
DENNY ISLAND
Shearwater
Saunders Island
Pole Island
Meadow Island
Whisky Cove
CAMPBELL ISLAND
N
85
84
83
82
81
80
79
78
800
1000
700
0
1000
2000 M

LEGEND

▲ PROPOSED WIND GENERATION SITE

— DISTRIBUTION LINE

B.C. HYDRO

MOUNT HAND
WIND TURBINE SITE
BELLA BELLA
FIGURE B.5-11

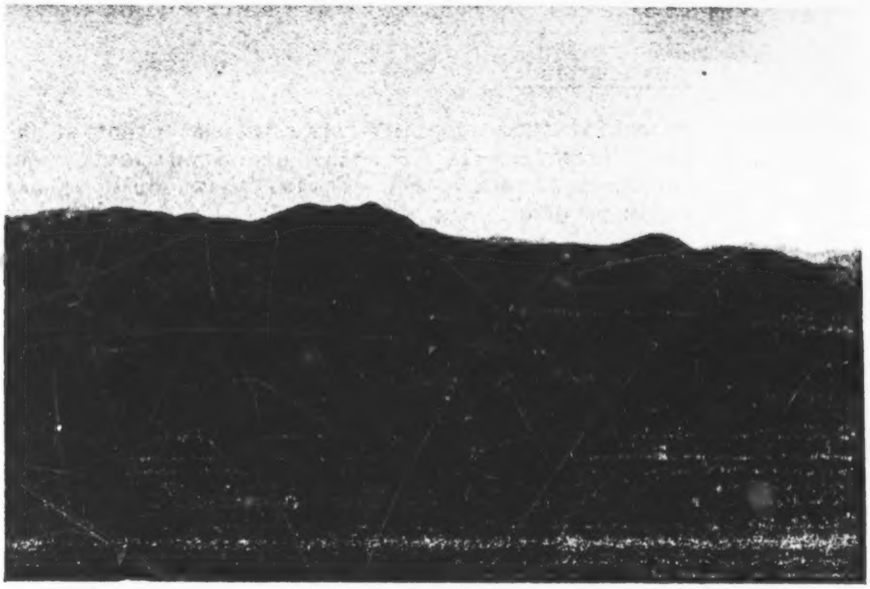


FIGURE B.5-12 View of the Williams Range from Hunter Island

FIGURE B.5-13 View of Mount Hand, New Bella Bella and Shearwater from the Williams Range

5.7 THERMAL

(a) Fuel Supply

(i) Introduction

Potential fuel supplies for a thermal plant at Norman Morrison Bay (Fig. B.5-14, B.5-15) are wood waste, wood from tree farms, peat and coal. These fuels could be used to produce steam or gas.

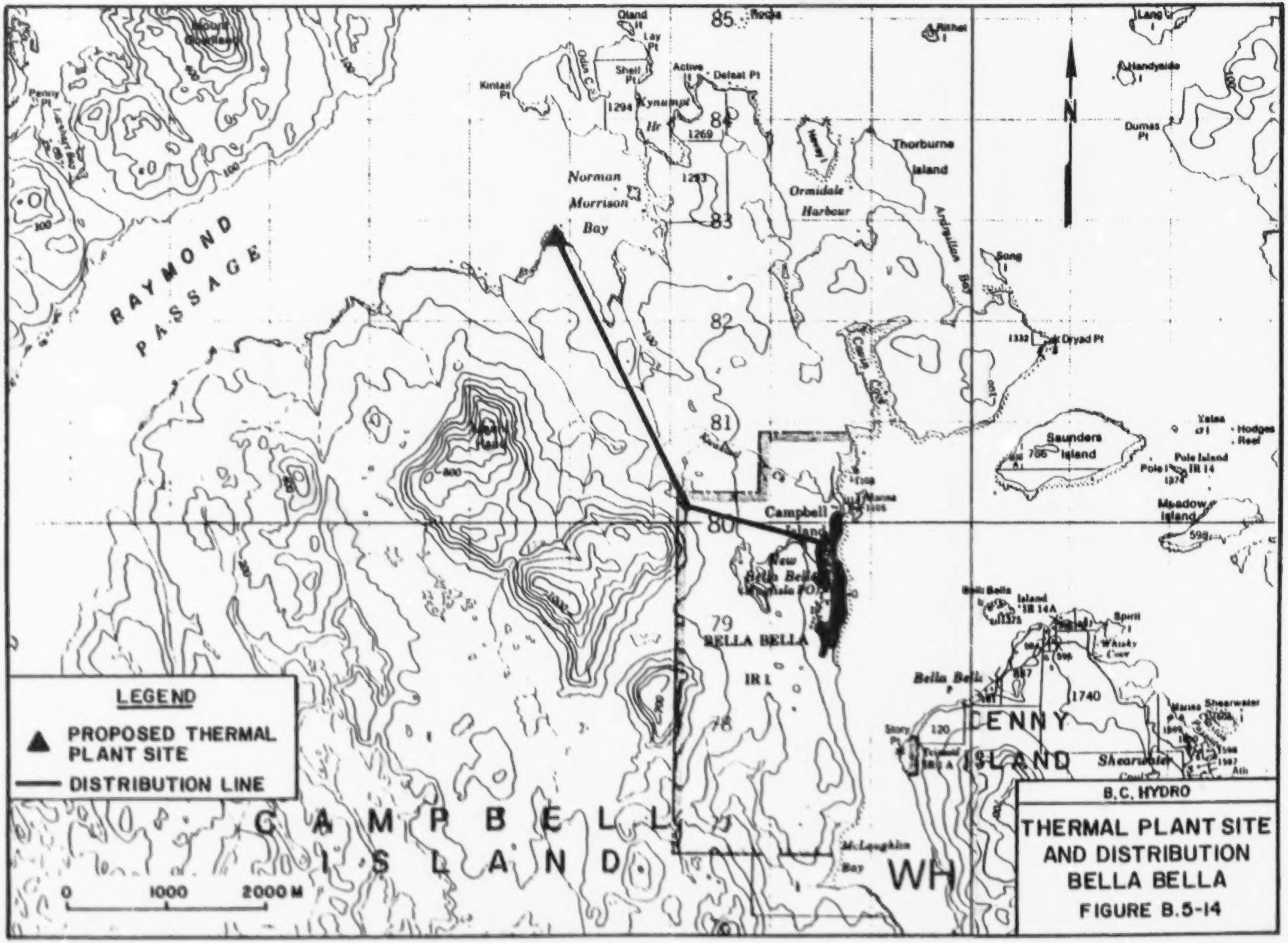
(ii) Biomass

A. Wood Waste

In order to generate 10.35 GW·h/a, approximately 9650 oven-dried tonnes (ODtonnes) of biomass would be required for a conventional wood-fired generating station at Bella Bella.

Wood fuel supply to a thermal generating station for Bella Bella would not be readily available in sufficient quantities from logging operations in the area. Both Shearwater and Bella Bella are isolated on separate islands. Schon Timber Limited is logging on Campbell Island in the vicinity of the potential thermal plant site at Norman Morrison Bay, but their operation will be finished in late 1984 and they will move to the Ocean Falls area (P. Calverly, Schon Timber Ltd., personal communication). Discussions with the B.C. Forest Service[15] indicates that at least another 40 000 m³ of merchantable timber and several times that amount of scrub timber could be available for a thermal generating station. In the long-term it would be possible to harvest the standing timber for wood fuel and replant faster growing red alder to provide a sustained yield for a wood-fired thermal generating station.

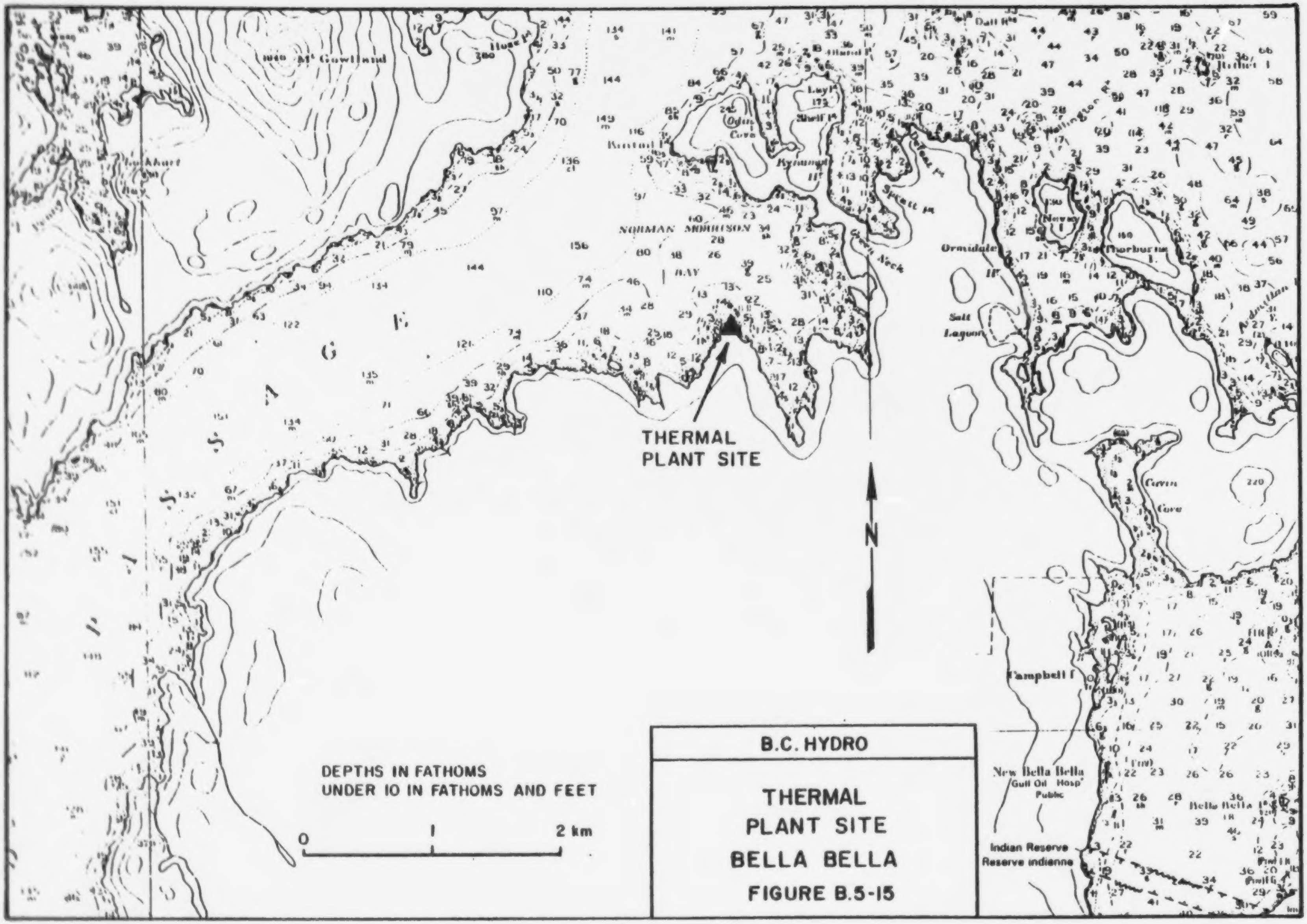
Several forestry companies have active logging operations in the area, but the total wood waste generated at the land sorts would not provide sufficient fuel to feed a 2 MW thermal generating station. Due to the dispersed locations of the wood waste on various islands in the area, one of the more feasible methods of recovering the available wood waste may be by using a barge-mounted hogger, similar to the one that Crown Zellerbach is operating from the Elk Falls mill on Vancouver Island (D. McQuillan, Crown Forest Products, personal communication).


LEGEND
▲ PROPOSED THERMAL PLANT SITE
— DISTRIBUTION LINE
0
1000
2000 M
N
RAYMOND PASSAGE
CAMPBELL ISLAND
DENNY ISLAND
WH
Norman Morrison Bay
Ormidale Harbour
Thorburne Island
Ardmillan Bay
Cavin Cove
Campbell Island
New Bella Bella
BELLA BELLA
IR 1
Bella Bella
Saunders Island
Meadow Island
Pole Island IR 14
Shearwater
Whisky Cove
Spirit
McLoughlin Bay
Kynumpt Hr
Kintail Pt
Oland
Lay Pt
Shell Pt
Active
Defeat Pt
Rocks
Rithet
Lang
Handyside
Dumas Pt
Song
Dryad Pt
Yatza
Hodges Reef
Story Pt
Penny Pt
Lockhart Bay
85
84
83
82
81
80
79
78
1740
120

B.C. HYDRO

THERMAL PLANT SITE AND DISTRIBUTION BELLA BELLA

FIGURE B.5-14


Mt Gowland
Lockhart Bay
Norman Morrison Bay
Odin Cove
Kynumpt Hr
Shelf Is
Spratt Pt
Ormidale Hr
Salt Lagoon
Nevay I
Thorburn I
Gavin Cove
Campbell I
New Bella Bella
Gull Oil
Hosp
Public
Bella Bella
Indian Reserve
Reserve indienne
THERMAL PLANT SITE
N
DEPTHS IN FATHOMS
UNDER 10 IN FATHOMS AND FEET
0
1
2 km

B.C. HYDRO

THERMAL
PLANT SITE
BELLA BELLA
FIGURE B.5-15

Whonnock Industries Limited operate land sorts at Kwatna Bay and Taleomey River near Bella Bella (Fig. B.5-16).[16] The combined annual cut ranges between 76 000 m^3 and 130 000 m^3. This produces a total of approximately 4500 m^3 of logging residue. Approximately 96 percent of this residue consists of slash and the remainder is at landings.

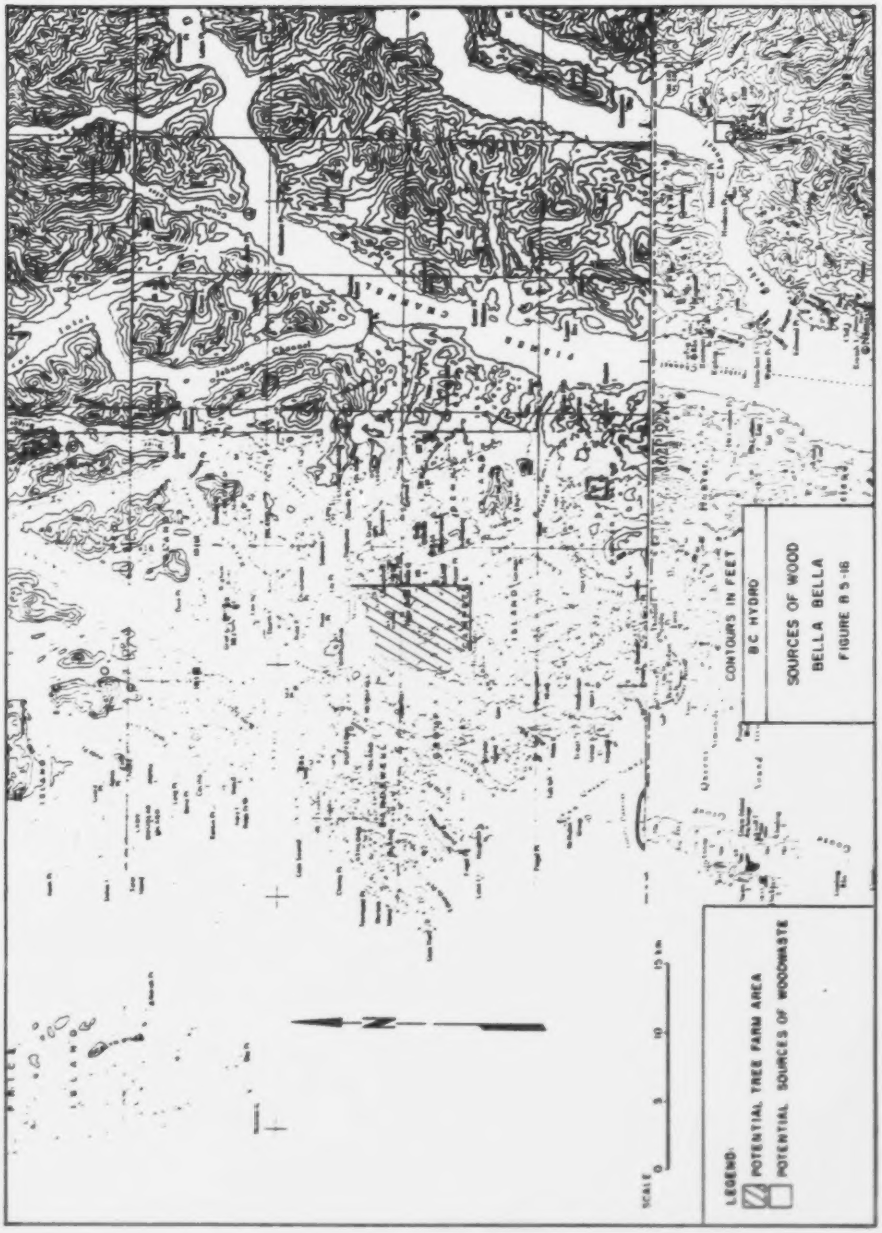
Western Forest Products Limited are planning to open a dry land sort at Collins Bay north of Bella Bella.[17] This land sort is expected to operate for 5 to 10 years depending on the economic climate. Production is expected to be 50 000 m^3/a of which 8 to 10 percent would be waste.

A proposed MacMillan Bloedel operation will develop a land sort at Nootum Bay near Namu and this is expected to generate the largest amount of wood waste in the area (Fig. B.5-16).[18] Assuming 7 percent of the production is generated as logging residues at the land sort, an average of 4400 ODtonnes/a could be available as a fuel source.

Another 3000 ODtonnes/a might be available from other logging land sorts. This would provide only about half of the wood fuel required for a 2 MW thermal generating station. Forest residues left along the logging roads could be recovered and could be sufficient to provide the remaining wood waste fuel, but the cost and logistics of collecting and handling the wood waste would adversely affect the economics.

B. Tree Farms

The most available and secure source of wood fuel for Bella Bella would appear to be from a tree farming operation on Campbell Island (Fig. B.5-16). The 40 000 m^3 of standing timber and the 80 000 m^3 or more of scrub forest,[15] if dedicated to the thermal generating station, could provide fuel for the initial 4 to 5 years of operation. Planting fast growing red alder on the existing logged-over timber leases near Norman Morrison Bay could provide part of a sustained yield harvest of wood fuel for a thermal generating station (Fig. B.5-17, B.5-18). It is assumed that sufficient land on Campbell Island could be made available to provide this fuel. As outlined in Appendix A of this report, red alder grown in the West Coast climate, could provide 4.24 ODtonnes/ha of wood fuel annually from an energy plantation.[19] This growth rate would require a 2400 ha (24 km^2) energy plantation (including the existing logged timber leases)



SOURCES OF WOOD
BELLA BELLA
FIGURE R 5-16

BC HYDRO
CONTOURS IN FEET
LEGEND:
▨ POTENTIAL TREE FARM AREA
☐ POTENTIAL SOURCES OF WOODWASTE
SCALE
0
5
10
15 km
N
Queens Sound

FIGURE B.5-17 Logging on Mount Hand

FIGURE B.5-18 View From Mount Hand toward Ornidale Harbour and Seaforth Channel

to provide fuel for the thermal generating station. An area roughly the size of one-quarter of Campbell Island would be required, necessitating close cooperation with the Indian band at New Bella Bella and with the B.C. Forest Service. Managing and harvesting such an energy plantation could be a significant source of employment for the area.

Several sources of wood waste and dedicated tree farm acreage could be available to provide fuel for a thermal generating station at Bella Bella. If such a power supply option is selected a detailed study would be necessary to confirm the availability and to identify and deal with the apparent constraints.

C. Peat

A study of peat resources in coastal British Columbia is being conducted by Agriculture Canada. Coastal sites are typically in slope bogs where the peat averages 1.8 m thick, but at one site the peat extended to a depth of 4.95 m.[20] The peat deposits are in areas where the terrain is gently undulating and where there are a few metres to a few tens of metres of relief. Bedrock is close to the surface and the overburden is predominantly glacial till which together account for the poor drainage and the numerous swamps, ponds, lakes and peat bogs. Vegetation is sparse except on the few steep hillsides where drainage is improved.

The Agriculture Canada study found that most of the peat deposits consist of thin surficial deposits of sphagnum peat overlying a thicker deposit of sedge peat. Sampling sites on Campbell Island are at approximately El. 95 m in bedrock controlled, hummocky terrain (Table B5-4).[21,22]

Refer to Appendix A for an explanation of peat classification. Some sites contain large intervals of organic sediments within the peat strata. In general the peat layer is thin, although there are some deeper basins which are small. There does not appear to be a source of thick, mineable peat in the area.

It is assumed that any thermal plant fired on peat would be effectively mine-mouth because of the high moisture content and the resulting high cost of moving the fuel. It is expected that no suitable site for economical peat harvesting could be found on Campbell Island.

TABLE B5-4

PEAT SAMPLES - CAMPBELL ISLAND*1

Site	Depth (cm)	Peat Type	Von Post Index
1	0 - 40	Fibric	1 - 3
	40 - 170	Mesic	5
	170 - 185	Woody, Sedimentary	8
	185 - 204	Mesic	5
2	0 - 28	Fibric	-
	28 - 112	Mesic	-
	112 - 294	Fibric	-
3	0 - 22	Fibric	-
	22 - 88	Mesic	-

---

*1 Supplied by Agriculture Canada, Research Branch.[22]

(iii) Coal

There are no local sources of thermal coal near Bella Bella. Coal is being delivered to the Ridley Island coal port near Prince Rupert. This coal presently comes from the Peace River coalfield in northeastern British Columbia, but it is expected that coal will eventually be shipped by Crows Nest Resources from their property near Telkwa, 235 km east southeast of Prince Rupert.

The air dried coal quality of Telkwa thermal coal is 1.2 percent residual moisture, 11 to 13 percent ash, 27 to 29 percent volatile matter, 59 percent fixed carbon and 1.0 percent sulphur.[23] The heating value is 28 890 kJ/kg (approximately 25 750 kJ/kg on an as received basis), the Hardgrove grindability is 60 and the ash fusion temperature is 1330°C. The rank of the coal is high volatile A to B bituminous.

The Telkwa property is expected to begin producing in 1986 if markets can be found. Reserves on the property are estimated to be 50 Mt.

The coal could be shipped by barge from Ridley Island to Bella Bella where a barge unloading facility and associated equipment would be required. The quantity required would be approximately 5000 t/a which includes a tonnage allowance of 20 percent for operating the plant.

(b) Generating Station Design

(i) Conventional Thermal

Thermal resources which could be used by an electrical generating plant at Bella Bella are wood waste, wood from tree farms, peat and coal. To meet the future requirements for Bella Bella a small thermal plant consisting of two 1000 kW steam turbine/generator sets could be constructed at a site on Norman Morrison Bay at the north end of Campbell Island (Fig. B.5-14, B.5-15). At least two of the 600 kW diesel units at Shearwater would also be required for peaking and emergency standby. It would not be necessary to move these units to the new site; they could continue to operate at the existing diesel plant site. An area of approximately 2 1/2 ha would be required if coal were the selected fuel, or 3 ha if waste wood were used as the fuel. The steam turbine units would be base loaded and would supply the total generation in 1990/91 with a capacity factor of 59 percent.

The major equipment items for a 2 MW (net) power plant would be the same as those previously outlined for the Bamfield plant (Part A, Section 5.7) except that two units would be required. It is assumed for this study that ash from the Bella Bella plant could be disposed of at the existing landfill.

(ii) Wood Gasification - Engine Generation

As described in Appendix A of this report, wood gasification-engine generation of electricity is another thermal generating option available for Bella Bella. The technology of wood gasification-engine generation is not fully developed at this time, but several systems are commercially available. The Imbert gasifier and Duetz (KHD) diesel generating set combination is one of the more advanced systems with a relatively successful operating history.[24]

Consequently the Imbert-Duetz (KHD) system has been used for the Bella Bella evaluation. It is assumed that a 2600 kW multiple unit system would be constructed for meeting the electrical requirements of Bella Bella in 1990/91. A system has been proposed which would consist of six power trains with automatic feed and ash removal systems, each including one gasifier per engine generator set and each having an output of 442 kW electrical.[25] Major equipment and off-site facilities would be similar to those outlined for the Bamfield station, but specifically designed to suit the larger units. The engine generator set would be based on an Imbert-type down draft gasifier model DU514 capable of producing 1160 m^3/h of low-Btu gas with an energy value of 4840 kJ/m^3 (130 Btu/ft^3). A Duetz (KHD) diesel generator set (model BGA 16M 816) operating at 1800 rpm would be capable of generating the 442 kW from 480 kg/h of oven-dry wood waste. In order to generate 10.35 GW·h/a, 11 200 ODtonnes of wood fuel would be required. The KHD Duetz gasification energy system product line is shown in Table B5-5. Table B5-5 lists several small diesel generator sets which are available and capable of operating on low-Btu gas.

The fuel requirements and operating characteristics of the Bella Bella units would be similar to those described for Bamfield.

5.8 GEOTHERMAL

The Bella Bella area is east of the Queen Charlotte Fault (Described in Section B6.0). The Queen Charlotte Fault is off the west side of the Queen Charlotte Islands and subparallel to the coast.[26] The Queen Charlotte Fault is a major transcurrent fault with substantial right lateral movement. The fault is contiguous with the Fairweather and Chatham Strait Fault splays to the north and with a subduction zone to

TABLE B5-5

DUETZ GASIFICATION ENERGY SYSTEM PRODUCT LINE

Generator Set Model Number		GA8M 816		GA16M 816		BGA16M 816[*3]	
Electrical output	kW	100	110	200	236	368	442
Frequency	Hz	50	60	50	60	50	60
Engine output	Shaft kW (hp)	110 (147)	130 (174)	219 (294)	260 (348)	400 (536)	479 (643)
Engine speed	r/min	1500	1800	1500	1800	1500	1800
Specific heat consumption	kJ/kW·h (Btu/kW·h)	11.0x10^3	(10.4x10^3)	11.0x10^3	(10.4x10^3)	11.0x10^3	(10.4x10^3)
Recoverable waste heat from: cooling system	kJ/h (Btu/h)	0.400x10^6 (0.379x10^6)	0.470x10^6 (0.446x10^6)	0.800x10^6 (0.758x10^6)	0.941x10^6 (0.892x10^6)	1480x10^6 (1.403x10^6)	1.77x10^6 (1.678x10^6)
Exhaust gas[*2]	kJ/h (Btu/h)	0.321x10^6 (0.304x10^6)	0.381x10^6 (0.361x10^6)	0.642x10^6 (0.609x10^6)	0.761x10^6 (0.721x10^6)	1.197x10^6 (1.135x10^6)	1.427x10^6 (1.353x10^6)

Gas Generator model number[*1]		DU 506		DU 509		DU 514	
Gas output[*1]	m^3/h (ft^3/h)	260 (9 200)	300 (10 600)	520 (18 400)	600 (21 200)	960 (33 900)	1 160 (41 000)
Heat output[*1]	kJ/h (Btu/hr)	1.26x10^6 (1.196x10^6)	1.45x10^6 (1.378x10^6)	2.52x10^6 (2.392x10^6)	2.90x10^6 (2.756x10^6)	4.64x10^6 (4.407x10^6)	5.62x10^6 (5.330x10^6)
Fuel consumption (wood, biomass)	kg/h (lb/h)	110 (243)	130 (287)	220 (486)	260 (574)	400 (882)	480 (1058)

[*1] Model number and other specifications depend on the specific heat value of the material to be gasified. These tables use an assumed gas specific heating value of 4804 kJ/m^3 (130 Btu/ft^3) with a 20 percent dry basis moisture content. Volumes are given at 0°C (32°F) and 1.0 bar (14.38 psi).

[*2] Based on an exhaust gas temperature of 120°C (248°F).

[*3] This unit is under development.

the south, off Vancouver Island. Although subduction zones generally provide good areas for geothermal exploration, the rate of subduction off Vancouver Island is relatively slow for geothermal development and active volcanism.

Andesitic volcanoes of the calc-alkalic suite (silica content: 56 to 61 percent) commonly develop approximately 150 km inland from a subducting oceanic plate boundary. Campbell and Denny islands are approximately 180 km inland from the oceanic plate boundary. They are along the projected line of the Principe Laredo Fault which is subparallel to the Queen Charlotte Fault.[27] Bella Bella is also at the western limit of the Anahim Volcanic belt, a line of calc-alkalic volcanoes which extends eastward toward McNaughton Lake. The volcanism is believed to be due to a migrating "hotspot" in the mantle. The "hotspot" caused melting and injection of molten rock into the crust. Near Bella Bella this volcanism is recognized today by the presence of Miocene volcanic and plutonic rocks (Refer to Geology in Section B6.0, Fig. B.6-1). More recent volcanic activity is both pre-glacial and post-glacial. The volcanic rocks are olivine basalts which have been identified on Dufferin Lake, Lady Douglas and other islands northwest of Bella Bella. These volcanic rocks are characteristic of a deep-seated mantle source with no evidence of a significant residence time in the crust. Therefore, little heat would have been transmitted to the crustal rocks. Although there is a long and recent history of volcanic activity in the Bella Bella area it does not necessarily indicate significant recent geothermal activity.

There are hot and warm springs at the following locations between Bella Bella and Bella Coola:

1. Link Lake
2. Nascall Bay
3. Eucott Bay
4. Talheo
5. Wash Wash river
6. Sheemahat River

These hotsprings are between 40 and 115 km from Bella Bella which is too far to be of particular interest for electrical power supply to Bella Bella. The hotsprings are not associated with recent volcanism.

Heat flow measurements have been obtained from the ocean bottom around King Island by the Pacific Geoscience Centre (T. Lewis, E.M.R., personal communication). The heat flows are typically low, but increase toward Bella Coola. These trends follow similar trends throughout the western coast of North America.

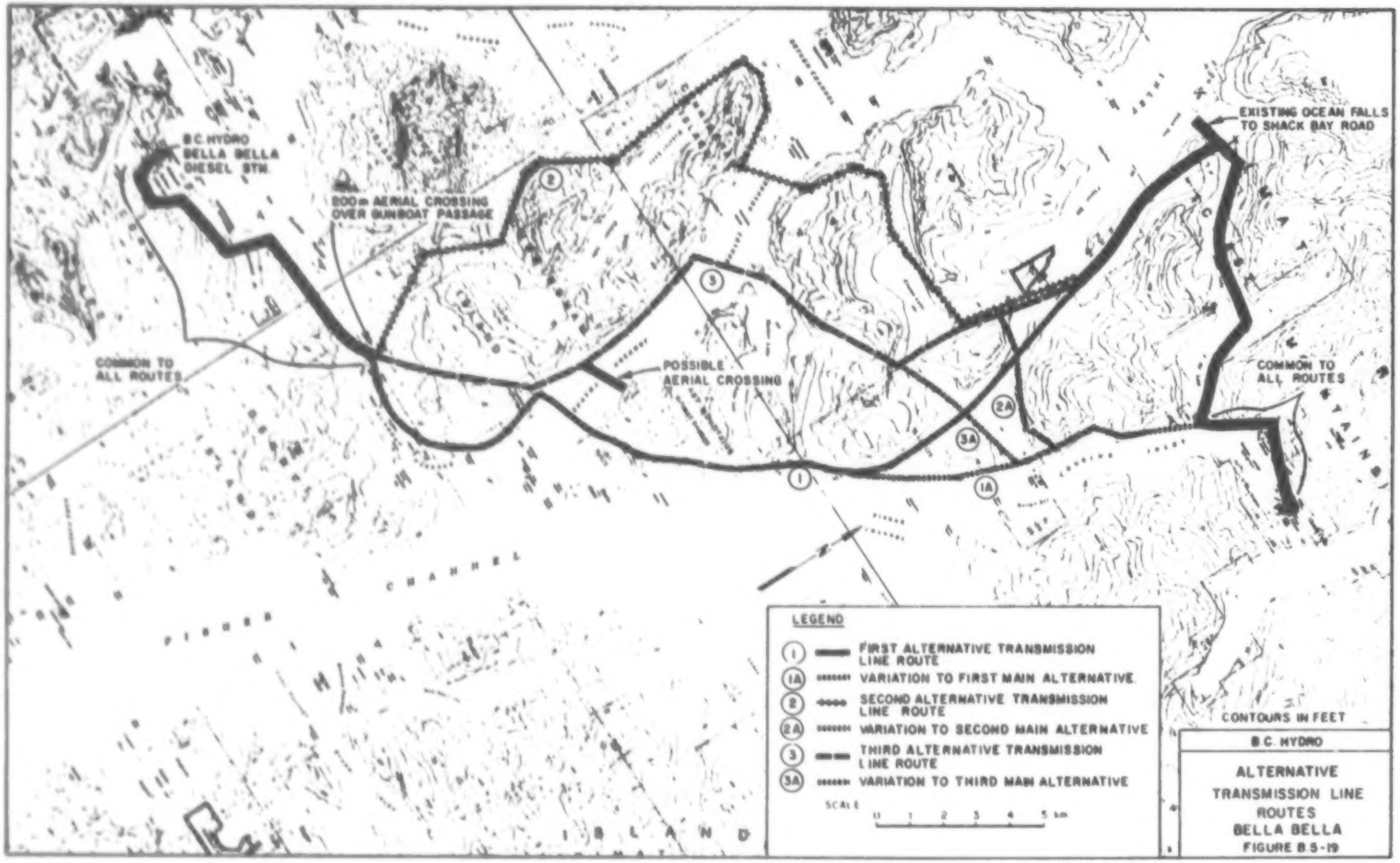
It is concluded that there is no near surface heat source of molten rock and no anomalous heat flows near Bella Bella. Therefore, there appears to be no potential for a geothermal resource for electrical power generation in the area.

5.9 TRANSMISSION

Reid, Crowther and Partners Limited completed a feasibility study in October 1983 which was jointly funded by the B.C. Cellulose Company and B.C. Hydro.[5] This study examined the feasibility of a transmission line from Ocean Falls to Bella Bella. Three principal routes and three variations were examined (Fig. B.5-19). The alternatives have the following characteristics which would affect the choice of the transmission line route:

	For	Against	Overland Length (km)	Underwater Length (km)
Route 1	Ocean access over most of route. Vegetation is generally sparse. No active slides or avalanche chutes.	More exposed than routes 2 and 3.	52	1.2
Route 1A	Shorter	Steeper terrain More danger of icing and high winds	44	1.2
Route 2	Provides logging access. Shorter underwater crossing. Best shelter from winter storms.	More road access required.	57	1.0
Route 2A	Shorter	Steeper terrain. More danger of icing and high winds.	53	1.0
Route 3	Easiest construction conditions. Least exposed to weather.	Steep terrain near Webster Lake.	52	1.5
Route 3A	Shorter	Steeper terrain. More danger of icing and high winds.	43	1.5

Aerial crossings across Johnson channel were not considered feasible because the route is used by low flying aircraft under adverse weather conditions, which are particularly common in winter.


B.C. HYDRO
BELLA BELLA
DIESEL STN.
200m AERIAL CROSSING
OVER GUNBOAT PASSAGE
COMMON TO
ALL ROUTES
POSSIBLE
AERIAL CROSSING
EXISTING OCEAN FALLS
TO SHACK BAY ROAD
COMMON TO
ALL ROUTES
CHANNEL
ISLAND
LEGEND
① FIRST ALTERNATIVE TRANSMISSION LINE ROUTE
(1A) VARIATION TO FIRST MAIN ALTERNATIVE
② SECOND ALTERNATIVE TRANSMISSION LINE ROUTE
(2A) VARIATION TO SECOND MAIN ALTERNATIVE
③ THIRD ALTERNATIVE TRANSMISSION LINE ROUTE
(3A) VARIATION TO THIRD MAIN ALTERNATIVE
SCALE
0 1 2 3 4 5 km
CONTOURS IN FEET
B.C. HYDRO
ALTERNATIVE
TRANSMISSION LINE
ROUTES
BELLA BELLA
FIGURE B.5-19

The overall physiographic characteristics of the routes vary from steep at Ocean Falls and as far as Gunboat Passage to gently undulating on Denny Island. The valley floors range from sea level to an El. 150 m. In most areas bedrock is intensely fractured and at or near the surface; therefore, setting holes for poles would commonly require blasting. There is little construction aggregate in the area. Vegetation is often sparse because of the thin soil cover and much of Denny Island is covered with muskeg. Most of the area was logged around 1916 and most larger trees are approximately 35 cm in diameter. There is some heavy timber along the shores of Clatse and Walker lakes; however, in much of the area the trees are overmature, but stunted.

The dam at Ocean Falls was built in 1913 and in 1925 it was raised to its present height of 50 m and partly rebuilt. The present powerhouse was built in 1917. In the 1960s and 1970s the generators were rewound and the original Woodward Governors and certain switchgear and related equipment were replaced. Detailed maintenance records are available.

Considerable deferred maintenance would be required at Ocean Falls in order to ensure that there would be a secure source of power. The main switchgear was scheduled for replacement in 1974, but the new equipment remains in storage. One turbine runner is scheduled for replacement. The penstock requires remedial work on 3 or 4 cradles and it requires a cleaning and exterior painting. Emergency closure gates should be installed. The town supply transformer rack should be moved and incorporated into the proposed 69 kV substation. The existing circuit breaker at the hydro plant should be replaced with a new unit which is in storage; the new unit would feed the 2.4 kV to 69 kV transformer. It is proposed that the two existing buses (each having 1 x 2150 kW and 1 x 5250 kW - 2400 V) be tied together through reactors on the roof of Substation B at the mill. Minor patching of the dam would be required and the dam should be upgraded to ensure that it meets present B.C. Hydro seismic standards. Logs and flotsam in the forebay area should be cleaned and the trash racks should be cleaned and repaired. Eventually the powerhouse should be automated except for start-up, synchronizing and stopping.

The transmission line from Ocean Falls to Bella Bella would be of woodpole construction and some parts with longer spans would require H-frame construction. The Reid Crowther report recommends the use of 2/0 ACSR conductors, but B.C. Hydro prefers higher strength 266.8 kcm ACSR conductors.[28] The operating voltage would be 69 kV with a 350 BIL impulse level. By using 2/0 ACSR conductors the line capacity would be 5000 kVA at a 0.8 power factor and 5 percent regulation. By using 266.8 kcm ACSR conductors the line capacity would be 9000 kV·A at a 0.8 power factor and 5 percent regulation.

The Reid Crowther report recommends that the submarine parts of the line consist of No. 1 copper, 3 conductors PILC SWA PVC cable.[5] For better security and unless the diesel station is retained for emergency, B.C. Hydro would prefer that four 1-conductor cables be installed with a separation of 30 to 50 m between them.[28] The fourth cable would be used when repairs are being made to one of the other cables. The four -conductor cable installation would have slightly higher losses than a 3-conductor cable, but this is not believed to be significant. The terminal ends would be at the same elevation in order to prevent compound migration in the solid-type PILC cable. Switching would be required at the terminal ends in order to permit cut-in of a fourth cable. The conductor size quoted in A EIC No. 1-68 is 500 kcm for solid PILC at 69 kV; another source recommends a minimum conductor size of 4/0.

A new switchyard would be required for Bella Bella.[5] The switchyard would contain a 69 kV circuit breaker, a 69 kV to 25 kV transformer, a 25 kV circuit breaker and a feeder regulator. The cost estimates assume a 69 kV to 25 kV transformation without LRC and without a communication control link to Ocean Falls. The transformer capacity would be 3000/4000 kVA ONAN ONAF. It is further assumed that there is only one protection panel at each end.

For this study it is assumed that the diesel station is totally dismantled and the transmission system upgraded to B.C. Hydro standards in order to guarantee the security of electrical supply at Bella Bella.

SECTION 6.0 - ENVIRONMENTAL FACTORS AFFECTING ALTERNATIVE ENERGY DEVELOPMENT AT BELLA BELLA

6.1 INTRODUCTION

A preliminary evaluation of the environmental impacts of alternative energy resource development at Bella Bella was conducted in conjunction with a preliminary engineering evaluation. The purpose was to determine any overriding environmental factors which would make a potential project unacceptable. This evaluation of environmental impacts consisted of a brief literature study and discussions with some government scientists and concerned residents of the community. The alternative sources for which environmental impacts were examined are the following: small hydro, tidal, wind, thermal (wood waste, tree farms and coal) and transmission (Fig. B.1-1).

6.2 CLIMATOLOGY

Precipitation normals for Bella Bella are shown in Table B6-1. Temperature data is unavailable for this location. Wind data is available for a short period (1942 to 1944) for the town of Shearwater; however, the closest anemometer in present use is located at Pointer Island on the west side of Fisher Channel. Fig. B.6-1 illustrates the Pointer Island data; it is evident that the north-south direction of the channel largely determines wind direction of these low level winds.

6.3 EXISTING RESOURCES

The communities of New Bella Bella, East Bella Bella and Shearwater are located on the Pacific Coast 480 km northwest of Vancouver. The communities are accessible by air and sea. Daily air service is provided to Denny Island from Vancouver via Port Hardy and ferry service is also available from Port Hardy.

New Bella Bella is located on the Bella Bella No. 1 Indian Reserve on Campbell Island. It has a population of approximately 1300 people of which approximately 1000 are Native Indians. Fifty percent of the population of New Bella Bella is under the age of 21 years. The communities of East Bella Bella and Shearwater, which are located on Denny Island, have a combined population of approximately 100 people. Most of these people are Caucasian.

The present diesel generating facility on Denny Island is connected to New Bella Bella via submarine cables. The present location of B.C. Hydro's generating facilities and service crew is a point of concern to

TABLE B6-1

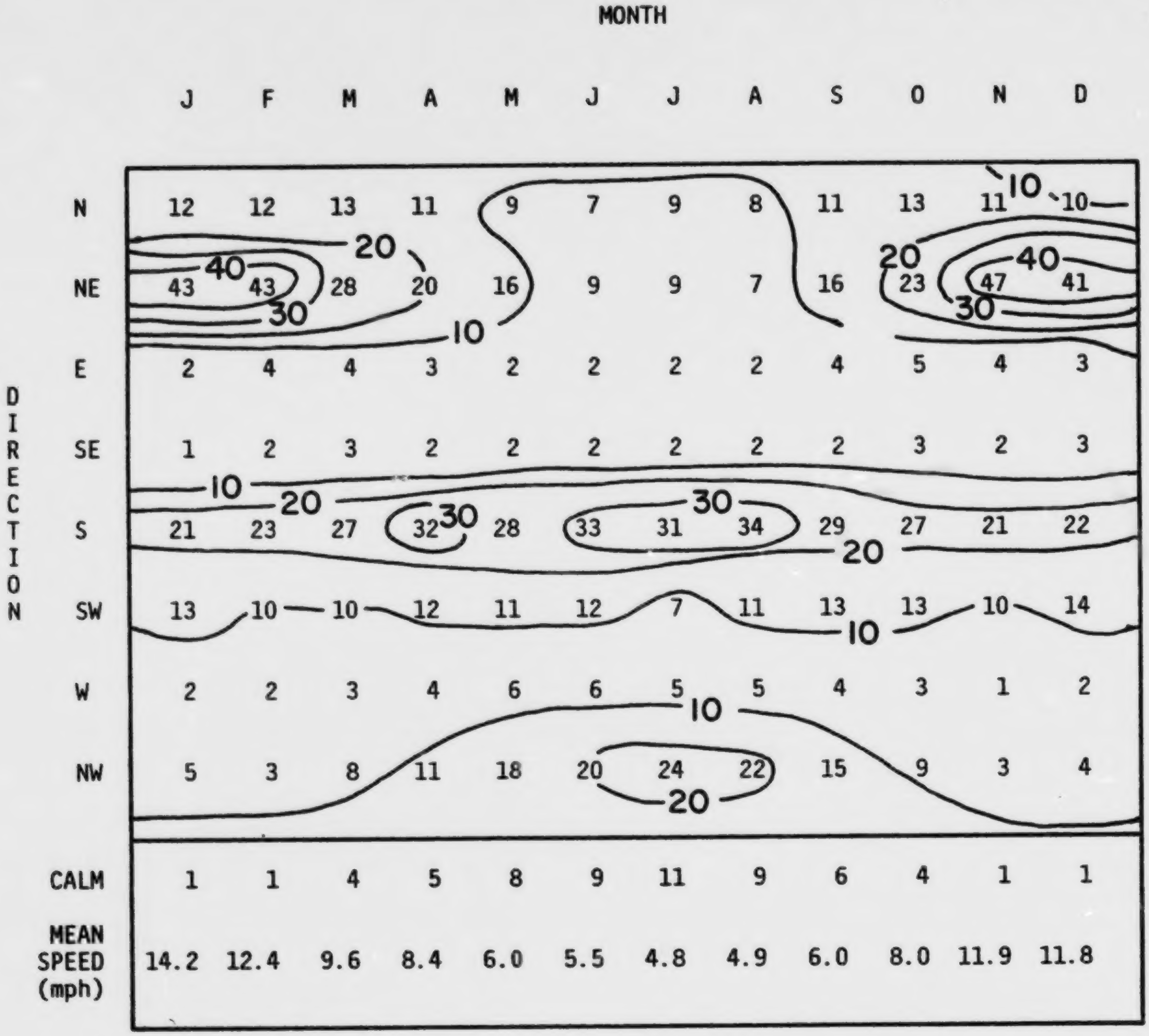
BELLA BELLA PRECIPITATION (mm) NORMALS

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
BELLA BELLA 52°10'N 128°9'W 12 m													
Rainfall	232.5	201.8	220.3	198.4	160.6	148.9	124.5	163.4	204.9	358.1	284.5	295.6	2591.5
Snowfall	32.1	16.7	10.2	9.9	0.0	0.0	0.0	0.0	0.0	0.0	6.3	17.0	86.2
Total Precipitation	264.6	218.6	230.5	200.3	160.6	148.9	124.5	158.9	204.9	358.1	291.1	312.6	2571.6
Standard Deviation, Total Precipitation	110.2	81.6	110.9	80.4	89.2	80.0	55.9	110.2	66.5	107.8	104.8	125.4	365.9
Greatest Rainfall in 24 hours	100.3	101.1	100.8	71.6	88.1	83.8	71.6	97.8	102.4	102.4	128.8	110.2	128.8
Years of Record	40	40	39	41	40	40	40	40	41	40	40	39	
Greatest Snowfall in 24 hours	40.6	27.9	23.1	25.4	T	0.0	0.0	0.0	0.0	T	30.5	35.8	40.6
Years of Record	40	40	39	40	40	40	40	41	41	41	40	38	
Greatest Precipitation in 24 hours	100.3	101.1	100.8	71.6	86.1	63.8	71.6	97.8	102.4	102.4	128.8	110.2	128.8
Years of Record	40	40	39	40	40	40	40	40	41	40	40	38	
Days with Rain	18	15	19	17	15	15	13	13	15	21	20	20	199
Days with Snow	6	3	3	1	0	0	0	0	0	0	1	4	18
Days with Precipitation	20	17	20	17	15	15	13	13	15	21	21	22	209

Environment Canada, Temperature and Precipitation, 1981.

Source: Canadian Climate Normals (1951 to 1980)

Note: Temperature data is unavailable for Bella Bella



MONTH	J	F	M	A	M	J	J	A	S	O	N	D
N	12	12	13	11	9	7	9	8	11	13	11	10
NE	43	43	28	20	16	9	9	7	16	23	47	41
E	2	4	4	3	2	2	2	2	4	5	4	3
SE	1	2	3	2	2	2	2	2	2	3	2	3
S	21	23	27	32	28	33	31	34	29	27	21	22
SW	13	10	10	12	11	12	7	11	13	13	10	14
W	2	2	3	4	6	6	5	5	4	3	1	2
NW	5	3	8	11	18	20	24	22	15	9	3	4
CALM	1	1	4	5	8	9	11	9	6	4	1	1
MEAN SPEED (mph)	14.2	12.4	9.6	8.4	6.0	5.5	4.8	4.9	6.0	8.0	11.9	11.8

DIRECTION

Fig. B.6-1 - Percentage Frequency Wind Direction (and Calms) and Mean Wind Speed by Months - Pointer Island Lightstation, B.C. (Oct 1969 to Dec 1976).

the New Bella Bella Band Council because the B.C. Hydro operation is not at the load centre in New Bella Bella. The Band Council have completed plans to expand housing and community facilities to accommodate 1500 people by 1988. These plans also include the construction of a cold storage and smoker plant.

Economic activity in the area is primarily related to the fishing industry, although some logging is being conducted on Campbell Island.

Locally the primary mode of travel is by boat. However, limited road systems exist on both Campbell and Denny islands.

(a) Small Hydro

Seven sites were selected as potential small hydro sites in the study area. Fig. B.5-1 shows the locations of these sites at Clatse Lake, Four Lakes, Ikt Lake, Lakes A, B, C and D, Sagar Lake, Walker Lake, and Webster Lake. Fisheries information is presently available only for Clatse Lake, Lake D, Webster Lake and Walker Lake. The creeks which flow from these lakes to the ocean contain salmon spawning habitat. Falls on most of these creeks prevent the passage of fish into the lakes; it is not known if a falls also blocks the upper part of the creek draining from Lake D.

The creek draining from Clatse Lake is approximately 1.5 km long with a 7 m falls which is 1.3 km from the mouth. Reported spawning areas of the stream total approximately 12 500 m^2. The Creek draining from Clatse Lake has the largest salmon run of the four lakes with mean annual escapements of coho, pink and chum of 150, 19 700, and 4200 respectively.

Kajusdus Creek appears to drain from Lake D and into Kakushdish Harbor, whereas Lakes A, B and C drain into Fisher Channel. The steep gradient of the creek draining from Lake A indicates that altering the existing flows is unlikely to have a significant impact on fisheries because there are no salmon runs in the creek. However, Kajusdus Creek has large salmon runs with mean escapements of 1300 sockeye, 1050 coho, 4400 pink and 4450 chum.[6] It is not known if diverting the drainage from Lake D would affect these salmon runs.

The creek draining from Webster Lake is 1.1 km in length. A water fall 15 m high and 1 km from the creek mouth forms the upstream spawning boundary. The mean escapement records for 1974 to 1983 show that mean coho, pink and chum populations of 350, 1850 and 3200 respectively, spawn in the stream.

The Creek draining from Walker Lake is approximately 0.7 km long with a 12 m waterfall 0.4 km from the stream mouth. The mean escapement of pink and chum salmon over the period 1974 to 1983 was 1300 and 800 respectively. The creek draining from Walker Lake has the smallest known fisheries resource of the three because only 400 m of the stream bed is available for spawning.

The remaining lakes, i.e. Four Lake, Sagar Lake and Ikt Lake, likely contain salmon spawning grounds; however, the extent of these is unknown.

For each of the above sites, with the exception of Sagar Lake, power development would involve a lake intake and a power house at the outflow to the sea. The Sagar Lake site would require damming of the natural lake outflow and diverting the lake discharge into Codville Lagoon. The potential site is in Sagar Lake Provincial Park which is used by the local people for recreation. The south end of the lake has gently sloping beaches which are accessible from Codville Lagoon. Development of the Sagar Lake site would result in land use conflicts and the potential elimination of fish habitat from the creek draining from Sagar Lake.

This engineering study has concentrated on Walker Lake as the most feasible small hydro site. The development of this site would involve a 1.5 km underwater crossing and a 27 km distribution line. The distribution line would also result in environmental impacts from the construction of a right-of-way. However, these effects would not likely limit development.

(b) Tidal

Seven potential tidal sites (Fig. B.1-1) have been considered in the Bella Bella area. These sites appear to have some potential for barrage-type tidal development. Environmental concerns resulting from tidal development have been described previously for Bamfield and include navigation and fisheries impacts.

Information has been received from the Bella Bella Subdistrict of Fisheries and Oceans on the three sites located on Campbell Island.

Hochstader Basin is the preferred tidal site on the basis of engineering and economics. The basin has been the site of a herring fisheries and spawning in the past. However, the present extent of this resource is unknown and local fisherman no longer fish in the basin. Federal Fisheries have also indicated that a small Coho salmon resource may use a stream and estuary within the basin, but an inventory is not available for confirmation. There are other fisheries resources in Hochstader Basin, but their extent is unknown. Any future study of Hochstader Basin would require a thorough search of Fisheries and Oceans' files and an on-site inventory.

The remaining two sites on Campbell Island (southeast and southwest) are potential herring spawning sites, although no confirming information is available. Other fisheries resources are undefined;

the southeast Campbell Island site is believed to have a small salmon resource.

Kakushdish Harbour on Denny Island is a major holding and rearing area for salmon stocks proceeding to and from the Kajusdus Creek and Kunsoot River. The mean salmon escapements for the Kajusdus Creek for the past 10 years (1974 to 1983) were 1300 sockeye, 1050 coho, 4400 pink and 4450 chum. Over the same period the mean escapements for the Kunsoot River were 550 coho, 6000 pink and 4900 chum. A barrage at the entrance to Kakushdish Harbour would affect both rivers. In particular, it would block the only migration route to the Kunsoot River. In the past herring have spawned within the harbour. Other fisheries resources are also present, but in unknown quantities. The Kunsoot Indian Reserve at the mouth of the Kunsoot River has several seasonal residences. The harbour is used extensively by local Indians for food fishing and recreation. From this preliminary assessment it is evident that a Kakushdish Harbour barrage would create significant impacts on fisheries and the local inhabitants.

Development of the remaining sites, Codville Lagoon, De Cosmos Lagoon and Lost Lagoon would impact the fisheries resources using the lagoons and associated creeks. All of these lagoons are believed to contain salmon resources. However, the sizes of the resources are unknown. A barrage at the entrance to Codville Lagoon would also restrict navigation and interfere with access to Sagar Lake Provincial Park.

(c) Wind

The wind turbine site on Mount Hand, 2.5 km west of New Bella Bella, is over 300 m above the flat terrain of Campbell Island. The hill is presently being logged and there is an access road to the summit. Approximately 18 ha of land would be required for an 800 kW wind farm on Mount Hand. The hill has good exposure for a wind power site, although there is no evidence of high wind effects on the hill top vegetation. Several years of wind data would be required to determine the potential of the site for wind power generation. The environmental implications of developing this wind site include land use conflicts and visual impacts. At this stage of study these impacts do not appear to be significant.

(d) Thermal

Of the various types of thermal generation considered for Bella Bella, the only practical method appears to be the use of coal in a conventional thermal plant. Coal would be barged from the Ridley Island coal port near Prince Rupert to the proposed Norman Morrison Bay thermal plant site on Campbell Island.

A thermal power development at Norman Morrison Bay could have some socio-economic impacts resulting from increased employment and an influx of construction workers. It is unlikely that local residents would benefit significantly, at least in the initial years of operation, because specialized labor would be required. Environmental impacts associated with gaseous, liquid and solid wastes from the operation of the plant, would be controlled by permits issued under the Waste Management Act.

(e) Transmission

The environmental effects of constructing a transmission line from Ocean Falls to Shearwater was studied by Reid Crowther and Partners Limited.[5] The environmental impacts of several routes (Fig. B.5-19) were considered and they concluded the following:

1. The heavy rainfall and flood events experienced in the area may present construction constraints during heavy precipitation periods, especially near riparian areas of recognized salmon streams.
2. Sensitive or unstable soils could be encountered around Clatse Lake and Walker Lake which could affect alternative routes 2 and 3.
3. Forestry use may be impacted, depending on the alternative route selected. Both routes 2 and 3 traverse Experimental Timber Sales held by B.C. Cellulose. Access development associated with these lines would have significant benefits to the forest company.
4. The wildlife resource is not considered highly productive relative to other areas east of the study area.
5. Recreation and tourism are not well developed in the area, where they do exist they are primarily associated with sport fishing.
6. The communities favour the construction of a transmission line from Ocean Falls to Bella Bella. The Heiltsuk Tribal Council favours route 2 with modifications to serve other reserves and future salmon enhancement project sites.

(f) Economic Geology

(i) Introduction

The regional geology, locations of mineral showings and deposits and mineral deposit land use were examined in order to determine the potential impacts of alternative energy developments and/or distribution line routes on mineral exploration and exploitation in the Ocean Falls-Bella Bella area. There are only a few mineral showings and deposits of base metals and industrial minerals in the area, but more deposits could be discovered.

(ii) Regional Geology

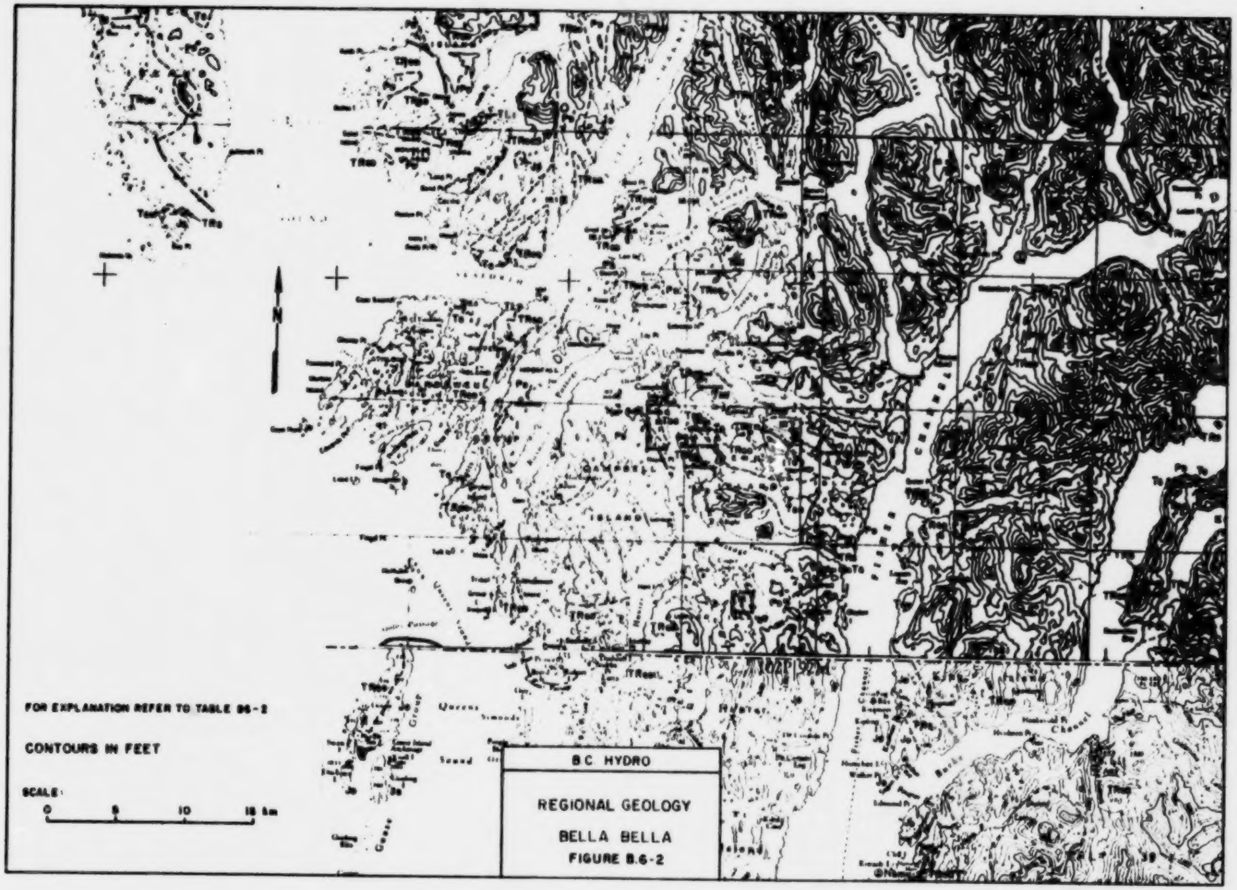
Denny and Campbell islands are within the Hecate Lowland. Campbell Island is mostly within a subdivision of this lowland called the Milbanke Strandflat which is an area mostly covered with abundant muskeg and poor drainage. There is a line of hills through Denny, Campbell and Horsfall islands and these hills rise to El. 520 m in the Williams Range on Denny Island.

The boundary between the Milbanke Strandflat and the Coast Mountains is sharp and extends through Cunningham Island and the northeast part of Denny Island. By contrast with the Milbanke Strandflat, the Coast Mountains are very rugged, with peaks as much as 1240 m high which are adjacent to the proposed route for a transmission line from Ocean Falls to Bella Bella. The terrain is characterized by oversteepened, U-shaped valleys and mountains which are approximately 760 m in elevation. The valleys are commonly filled with elongate lakes or they form fjords where the valleys have been deepened below sea level.

Bedrock in the Bella Bella-Ocean Falls area ranges from Permian(?) or older to Recent (Fig. B.6-2 and Table B6-2).[27,29] The oldest rocks are gneisses and amphibolites of the almandine-amphibolite facies which are exposed on both sides of Dean and Burke channels, near Ocean Falls. These outcrops comprise one of a series of northwest-trending belts.

Gneissic diorite metasedimentary rocks and greenstone of Paleozoic age are exposed in isolated zones adjacent to Burke and Fisher channels. These rocks are exposed on many of the outer islands, including Campbell and Denny islands. Metamorphism in this unit is also of almandine-amphibolite grade. The foliations trend northwest to west-northwest, parallel or subparallel to the trend of the rock units.

These units have been intruded by a series of Middle Triassic(?) plutons consisting of foliated quartz diorite and grandodiorite. The contacts with other plutonic rocks are either gradational or discordant depending on the age relationship between the plutonic rocks. The foliation is variable over the map area, but it is locally consistent. These Middle Triassic(?) intrusions are exposed over much of the area.


FOR EXPLANATION REFER TO TABLE B6-2
CONTOURS IN FEET
SCALE:
0
5
10
15 km
N
Queens
Sound

B C HYDRO

REGIONAL GEOLOGY

BELLA BELLA

FIGURE B.6-2

TABLE B6-2

TABLE OF FORMATIONS

CENOZOIC

QUATERNARY

PLEISTOCENE TO RECENT

PGL	Unconsolidated sand, gravel and till
TLI	Lake Island Formation - basalt and olivine basalt flows, scoriae and ashes

TERTIARY

MIOCENE

TRL	Rhyolite lava, tuff and breccia, quartz-feldspar porphyry
TG	Granite and syenite

OLIGOCENE AND/OR MIOCENE

TBB	Bella Bella Formation - andesitic flows and volcanic breccia, minor greywacke, slate and conglomerate

PALEOCENE AND EOCENE (MIDDLE TRIASSIC?)

TQM	Quartz monzonite

MESOZOIC

MIDDLE AND/OR LOWER JURASSIC

JD	Diorite, gabbro and norite

TRIASSIC

TRS	Schist, quartzite, limestone, amphibolite and conglomerate

MIDDLE TRIASSIC

TRQD	Quartz diorite and granodiorite

PALEOZOIC

PERMIAN (?) OR OLDER

PD	Gneissic diorite, metasedimentary rocks and greenstone
PG	Gneiss and amphibolite

Triassic(?) metasedimentary rocks, schist and metavolcanic rocks are exposed in narrow belts scattered over the area. This unit consists of schist, quartzite, limestone, amphibolite and conglomerate which range from greenschist facies on the outer coast to granulite facies to the east; some of the lower metamorphic grades have resulted from retrograde metamorphism. Both foliation and bedding commonly trend northwesterly.

There are scattered occurrences of Middle and/or Lower Jurassic diorite, gobbro and norite between Ocean Falls and the outer islands. The foliations are faint to distinct and their attitudes are variable, but they commonly trend northwesterly. The contacts are commonly gradational, but some of the intrusions contain xenoliths along the margins.

Eocene to Paleocene quartz monzonites comprise stocks and wide northwest-trending dykes which are scattered over the area. Some exposures attributed to this unit may be part of the Middle Triassic(?) intrusive episode. The rock is generally massive, lacks foliation and the contacts are sharp.

Oligocene and/or Miocene andesitic volcanic rocks of the Bella Bella Formation are exposed in an east-west-trending zone over Denny Island and a small part of Campbell Island. These volcanic rocks form the western limit of the Anahim volcanic belt which is believed to be due to the migration of a mantle hotspot which presently lies below the McNaughton Lake area of central British Columbia. This unit consists of a series of flows, volcanic breccia and minor greywacke, slate and conglomerate. Kakushdish Harbor is underlain by this unit and the harbor is in a northwest-plunging syncline where bedding attitudes are variable, but the dips are below 45°.

The earlier rock units are intruded by Miocene granite and syenite which form a northeast-trending belt between Fisher and Burke channels as well as other small plutons which are scattered over much of the area. The rock is massive and homogeneous. The contacts between this unit and the overlying volcanic rocks is gradational. Therefore, these intrusions may be related to the volcanic rocks.

Miocene rhyolite lava, tuff and breccia together with quartz-feldspar porphyry form small exposures on King and Denny islands.

The pre- and post-glacial Lake Island Formation consists of basalt and olivine basalt flows, scoria and ashes. This unit is exposed in small areas over some of the outer islands northwest of Bella Bella. The flows are subhorizontal to gently tilted.

Some of the stream valleys are partly filled by thick sedimentary piles consisting of sand, gravel and till.

(iii) Mineral Deposits

The mineral deposits of the Bella Bella area are summarized in Table B6-3 and their locations are illustrated in Fig. B.6-3. There are eight showings within the area and only two of these, Lagoon Bay (3) and Beale's Quarry (4) are in locations where they could be affected by an alternative to diesel power generation at Bella Bella.[30] The Lagoon Bay showing could be affected by a tidal installation at Lagoon Bay and Beale's Quarry could be affected by transmission from Ocean Falls.

The Lagoon Bay (3) deposit is on the north shore of Lagoon Bay. The showing consists of a small deposit of perlite (volcanic glass) in a small, unmapped exposure of the Bella Bella Formation.

Beale's Quarry (4), also called Cunningham's Quarry and the Gunboat Passage limestone deposit, is on the north shore of Gunboat Passage. The deposit consists of white to blue, coarse-grained, siliceous limestone in a sequence of Triassic, metasedimentary rocks. The limestone is intruded by numerous dykes and sills. The deposit was quarried for lime for the pulp mill at Ocean Falls from 1923 to 1934 and from 1948 to 1949. These limestone deposits may be suitable for sulphur absorption in a thermal plant.

(iv) Discussion

Maps of mineral deposit land use[31,32] (Fig. B.6-3 and Table B6-4), mineral showings and mineral claims can be related to geology (Fig. B.6-2) and the areas of highest mineral potential predicted. Most of the areas associated with the alternatives to diesel power generation fall into Category 4 where there is some indication of mineral potential, but very little work has been done because of the remoteness of the area. There are a few small areas adjacent to Johnson Channel and Lama Passage which are designated Category 3C, where no significant deposits are known, but small deposits are possible and exploration is likely to occur.

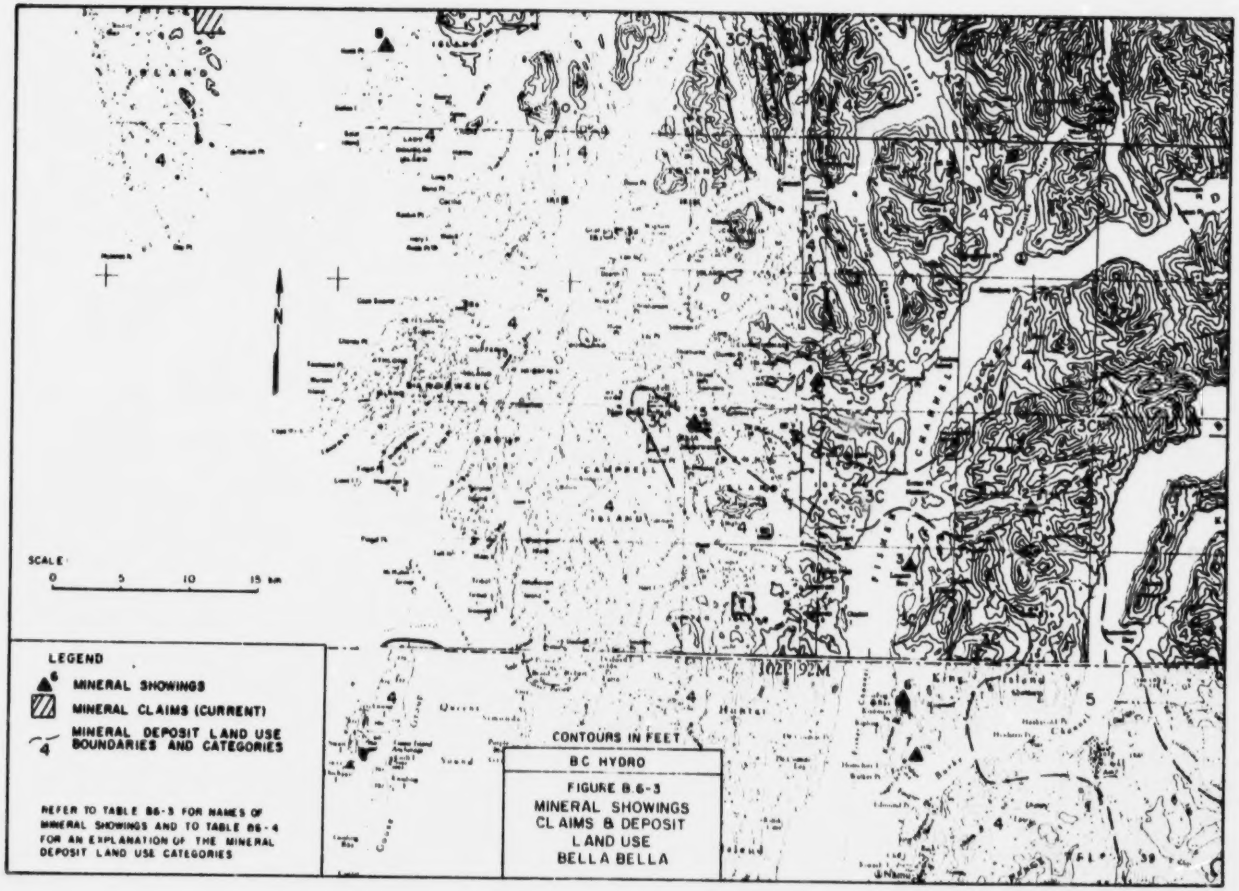
(v) Conclusions

There are no significant conflicts between mineral development and any of the alternatives to diesel electrical power generation at Bella Bella. The geology may be favourable for the discovery of small deposits, but no deposits are being

TABLE B6-3

MINERAL SHOWINGS NEAR BELLA BELLA

Showing No.	Name	Formation	Product(s)
1	Last Chance	-	Mo
2	Promise Well	-	Fe, Cu, U
3	Lagoon Bay	Bella Bella	Perlite
4	Beale's Quarry	-	Limestone
5	Denny Island	-	Perlite
6	Kisameet Bay	-	Clay
7	King Island	-	Limestone
8	Suzette Bay	-	Limestone



LEGEND
MINERAL SHOWINGS
MINERAL CLAIMS (CURRENT)
MINERAL DEPOSIT LAND USE BOUNDARIES AND CATEGORIES
REFER TO TABLE B6-3 FOR NAMES OF MINERAL SHOWINGS AND TO TABLE B6-4 FOR AN EXPLANATION OF THE MINERAL DEPOSIT LAND USE CATEGORIES
SCALE
0
5
10
15 km
N
CONTOURS IN FEET
102P
92M
4
3C
5
King Island
Hunter
Queens Sound

BC HYDRO

FIGURE B.6-3
MINERAL SHOWINGS
CLAIMS & DEPOSIT
LAND USE
BELLA BELLA

TABLE B6-4

CATEGORIES OF MINERAL DEPOSIT LAND USE

AREA CLASS	
1	AREA CONTAINING OREBODIES IN PRODUCTION OR ABOUT TO GO INTO PRODUCTION; GEOLOGIC ENVIRONMENT HIGHLY FAVOURABLE; AREA OF INTENSIVE EXPLORATION. 1A LARGE DEPOSITS KNOWN OR PROBABLE 1B MEDIUM DEPOSITS KNOWN OR PROBABLE 1C SMALL DEPOSITS KNOWN OR PROBABLE
2	SOME DEPOSITS KNOWN; TYPE OF OCCURRENCE AND GEOLOGICAL ENVIRONMENT FAVOURABLE; SOME EXPLORATION AT ADVANCED STAGES; CONTINUED EXPLORATION. 2A LARGE DEPOSITS POSSIBLE 2B MEDIUM DEPOSITS POSSIBLE 2C SMALL DEPOSITS POSSIBLE
3	NO SIGNIFICANT DEPOSITS KNOWN; GEOLOGICAL ENVIRONMENT FAVOURABLE; PRESENT AND FUTURE EXPLORATION LIKELY. 3A LARGE DEPOSITS POSSIBLE 3B MEDIUM DEPOSITS POSSIBLE 3C SMALL DEPOSITS POSSIBLE
4	SOME INDICATION OF MINERAL POTENTIAL; GEOLOGIC STATUS INDETERMINATE AT PRESENT; EXPLORATION POSSIBLE.
5	NO INDICATION OF MINERAL POTENTIAL; EXPLORATION UNLIKELY.
D	SAND, GRAVEL, CLAY, ALLUVIUM, TILL OR DRIFT WHICH COVER AREAS OF VARIED MINERAL POTENTIAL.

utilized at present. There are likely to be local sources of limestone for sulphur sorption if this is required.

SECTION 7.0 - ENERGY COSTS

7.1 INTRODUCTION

Energy cost estimates were made for the alternatives to diesel generation which appear to be technically feasible. These alternatives are small hydroelectric generation at Walker Lake and Lakes A, B, C and D, tidal generation at Hochstader Inlet, wind generation at Mount Hand, wood-fired thermal, wood gasification-engine generation and coal-fired thermal at Norman Morrison Bay and transmission from Ocean Falls.

7.2 DIESEL

The construction cost of the building, facilities and mobiles at the Bella Bella diesel generating station is estimated to be $1.859 million [Cost includes the addition of another 600 kW diesel generator in 1989/90] (Table B7-1). The plant burns No. 2 fuel oil which in December 1983 cost $0.332/L (Table B7-2). The capital cost of the plant is low, but the gross unit energy cost is high at 158 mills/kW·h. The cost of fuel is approximately 65 percent of the cost of energy (1984 $) assuming December 1983 fuel costs and projected 1990/91 fuel consumption.

7.3 SMALL HYDROELECTRIC

One of the proposed sites for small hydroelectric development is at Walker Lake, 18.5 km northeast of Bella Bella. The construction cost of this small hydroelectric generating facility is summarized in Table B7-3.

It is assumed that, because of the difficult access, a 1.5 km access road, clearing along the penstock right-of-way and clearing around the various facilities would cost a total of $200,000. An allowance of $150,000 has been made for protecting fish runs on the drainage from Walker Lake.

The basic components of the generating facilities have been identified and the costs estimated. The penstock (800 mm in diameter) is assumed to consist of 300 m of series 45 polyethylene pipe at a cost of $133,000/km, 100 m of series 60 polyethylene pipe at a cost of $173,000/km and 500 m of steel pipe at a cost of $140,000/km. There are additional allowances of $140,000 for labour and equipment and $177,000 for indirect costs and a remote location allowance resulting in an overall cost of $430,000. The intake including materials and labour is estimated to cost $700,000; other indirect costs and a remote location allowance are estimated to be $490,000 for a total installed cost of

TABLE B7-1

CONSTRUCTION COSTS FOR THE BELLA BELLA[*1] DIESEL GENERATING STATION (k$)

Station and Stationary Diesels and Other Facilities	$1319
Mobiles[*1]	540
TOTAL	$1859

[*1] Asset value (March 1982).

[*2] Includes 600 kW unit to be added in 1989/90.

TABLE B7-2

SUMMARY OF COMPARATIVE ENERGY COSTS[*1] - BELLA BELLA

	Diesel	Small Hydroelectric		Tidal	Wind	Thermal			Transmis
						Wood	Wood-Gas	Coal	
	Shearwater	Walker Lake	Lakes A,B,C,D	Hochstader Basin	Mount Hand	Norman Morrison Bay	Norman Morrison Bay	Norman Morrison Bay	Ocean Fa Bella Be
Plant and Transmission/ Distribution Characteristics									
Plant Capacity (MW)	3.60	1.10	0.50	2.00	0.80	2.00	2.60	2.00	14.0
Capacity Factor (%)	33	80	80	40	32	59	45	59	-
Annual Energy (GW·h)	10.35	7.70	3.50	7.00	2.26	10.35	10.35	10.35	10.3
Type of Fuel	No.2 Fuel Oil	-	-	-	-	Wood	Low-Btu Gas	Coal	-
Cost of Fuel	\$0.332/L \$8.47/GJ	- -	- -	- -	- -	\$80.55/t[*2] \$4.80/GJ	\$80.55/t[*2] \$4.80/GJ	\$61.45/t \$2.40/GJ	- -
Construction Period (a)	-	3	2	2	1	2	2	2	2
Plant Life (a)	20	40	40	40	20	35	20	35	-
Transmission/Distribution Life (a)	30	30	30	30	30	30	30	30	30
Capital Costs									
Plant Construction Cost[*3] (k\$)	1 859	5 662	3 000	11 470	4 200	8 627	9 215	7 866	-
New Transmission/Distribution Construction Cost[*3] (k\$)	-	1 889	700	560	80	225	225	335	4 88
New Substation Construction Cost[*3] (k\$)	-	150	-	-	-	462	462	462	1 39
Total Construction Cost[*3] (k\$)	1 859	7 701	3 700	12 030	4 280	9 314	9 902	8 553	6 279
Project Cost[*4] (\$/kW)	516	9 159	9 640	7 218	5 885	5 123	4 157	4 704	528
Total Capital Cost[*5] (k\$)	1 859	11 171	5 313	15 915	5 132	11 483	12 112	10 415	8 141
Annual Costs									
Operation and Maintenance Cost[*6] (k\$)	444	256	115	372	95	746	648	684	560[*8]
Fuel Cost (k\$)	1 058[*7]	-	-	-	-	819	959	305	-
Amortization Cost (k\$)	137	584	275	809	376	619	878	562	471
Total Annual Cost (k\$)	1 639	839	390	1 182	472	2 184	2 485	1 551	1 031
Gross Unit Energy Cost (mills/kW·h)	158	109	111	169	209	211	240	150	100

[*1] At 4 percent net interest rate.
[*2] Oven-dried tonne.
[*3] Includes engineering.
[*4] Includes construction and contingency.
[*5] Includes construction, contingency, overhead and IDC.
[*6] Includes taxes.
[*7] The equivalent energy cost of No. 2 fuel oil is 102 mills/kW·h.
[*8] Includes electrical energy cost.

TABLE B7-3

CONSTRUCTION COSTS FOR THE PROPOSED WALKER LAKE SMALL HYDROELECTRIC GENERATING STATION (k$)

Land and Water Rights	100
Access Road and Clearing	200
Camp Costs and Administration	300
Environmental	150
Penstock	430
Intake	1190
Powerhouse	680
Turbine/Generator Set	935
Installation	295
Surge Tank	100
Instrumentation	150
Subtotal	4530
Engineering (@ 25%)	1132
Total Plant Construction Cost	5662
Transformer/Switchgear	120
Distribution: Overhead	1299
Submarine	400
Engineering (@ 12%)	220
Subtotal	2039
TOTAL CONSTRUCTION COST	7701

$1,190,000. The estimated cost of the powerhouse structure, tailrace, riprap, crane, etc. is $400,000, and other indirect costs and a remote location allowance add an additional $280,000 for a total of $680,000. A 1.1 MW, 900 RPM turbine/generator unit is estimated to cost $550,000; an additional $385,000 has been estimated for indirect costs and an allowance was made for the remote location resulting in a total of $935,000. Installation is expected to cost $295,000. The costs of a surge tank and instrumentation are estimated to be $100,000 and $150,000 respectively. The subtotal for the cost of the plant is $4,530,000.

The cost of a 25 kV overhead distribution line from Walker Lake to Shearwater is estimated to be $48,000/km over a distance of approxi mately 27 km. A submarine cable crossing would be required under Johnson Channel at an estimated cost of $400,000. The cost of a transformer, switchgear and engineering are also listed in Table B7-3. The overall capital cost for a small hydroelectric plant and associated distribution is estimated to be $7,701,000.

Fixed costs were calculated as percentages of the uninflated construction cost and variable charges were related to energy production as summarized in Table AC2-1 and Appendix E2. The gross unit energy cost for small hydroelectric generation at Walker Lake near Bella Bella is estimated to be 109 mills/kW·h.

The second proposed site for small hydroelectric development is on the creek draining Lake A, 13 km south southeast of Shearwater on Denny Island . No layout has been proposed because of a lack of information about the site which was not visited on the field trip to Bella Bella. The construction cost for an installation at Lakes A, B, C and D is estimated to be $3,000,000 which is based on a Thorsen Creek (Bella Coola) estimate by B.C. Hydro ($6000/kW of installed capacity). The cost includes a small dam across Kajusdus Creek at the outlet from Lake D as well as a dam and intake across the outlet from Lake A. A road approximately 1.5 km long would be required from Fisher Channel to the intake. The penstock would extend 0.5 km from the outlet of Lake A to a point on Fisher Channel near the mouth of the creek draining from Lake A.

Other costs include land, water rights, some clearing costs and administration, environmental protection, a turbine/generator set, installation of facilities, a surge tank, instrumentation and engineering. Assuming an installed cost of $50,000/km, a 25 kV, 3-phase, 14 km distribution line from the powerhouse to Shearwater would cost approximately $700,000.

The estimated costs are summarized in Table B7-2 and Appendix E. Fixed costs were calculated as percentages of the uninflated construction cost and variable charges are related to energy production as summarized in Table AC2-1 and Appendix E. The gross unit energy cost for small hydroelectric generation at Lakes A, B, C and D near Bella Bella is estimated to be 111 mills/kW·h.

7.4 TIDAL

The tidal power facilities proposed for the entrance to Hochstader Inlet would comprise secondary dykes in the two smaller entrance channels, and a main dyke, powerhouse and sluiceway in the largest channel. The principal design parameters for the project are listed in Table B7-4. The proposed installed capacity of 2 MW is based on meeting the expected base load in 1990/91. The estimated energy output of 7 GW·h/a is equivalent to an annual capacity factor of 40 percent. This capacity factor is higher than for most tidal plants and reflects the fact that at 2 MW the potential of Hochstader Inlet would be under utilized.

The dykes are assumed to be constructed of dumped rockfill with an impervious till core to prevent seepage. The powerhouse and sluiceway structures would be constructed as caissons which would be floated into position and sunk onto a prepared foundation.

Capital costs for the layout described above have been estimated based on procedures similar to those used for Bamfield Inlet. The details of the estimate are shown in Table B7-5 which summarizes direct costs plus an allowance for engineering (12 percent).

Annual costs for operation and maintenance, insurance and general expenses were estimated to be 1.2 percent of the plant capital cost.[13] All of the capital and annual costs are summarized in Table B7-2 and Appendix E. The unit energy cost in 1990/91 is estimated to be 169 mills/kW·h which is slightly more than diesel generation.

7.5 WIND

The cost estimate for wind generation at Bella Bella is based on installing four 200 kW horizontal axis wind turbines. The installed cost of these wind turbines is estimated to be $1,050,000 each based on estimates in Tennis (1983).[13] It is assumed that a 2.5 km, 3-phase, 25 kV distribution line would be constructed to New Bella Bella at an installed cost of $80,000.

The capital costs and annual costs are summarized in Table B7-2 and Appendix E. The gross unit energy cost for wind generation at Bella Bella is estimated to be 209 mills/kW·h.

7.6 THERMAL

(a) Wood-Fired Thermal Plant Costs

(i) Bella Bella Wood Fuel Costs

The processed wood fuel costs for a thermal generating station at Norman Morrison Bay are summarized in Table B7-6. The most

TABLE B7-4

HOCHSTADER BASIN TIDAL PROJECT
PRINCIPAL DESIGN PARAMETERS

Installed Capacity	2000 kW
Annual Energy	7 GW·h/a
Powerhouse Data:	
- number of units	2
- rated head	3.5 m
- rotor diameter	3.0 m
- floor area	430 m^2
Sluiceway Discharge Area	32 m^2
Dyke volume:	
- main dyke	11 000 m^3
- secondary dykes	20 000 m^3
Distribution Line Length	10 km

TABLE B7-5

HOCHSTADER BASIN TIDAL PROJECT
CONSTRUCTION COST
(k$)

Access and Site Preparation	100
Dykes	1550
Sluiceway	1920
Powerhouse	
Turbine/Generators	4200
Civil Works	1620
Electrical and Miscellaneous	650
Subtotal	10 040
Equipment	
Switchyard	200
Engineering (@ 12%)	1230
Total Plant Construction Cost	11 470
Distribution and Substation	500
Engineering (@ 12%)	60
Total Distribution-Substation Construction Cost	560
TOTAL CONSTRUCTION COST	12 030

TABLE B7-6

BELLA BELLA THERMAL GENERATING STATION
PROCESSED WOOD FUEL COST[*1]
SUMMARY

(Cost in March 1984 Canadian Dollars per Oven-dried Tonne)

Cost Item	Source of Raw Wood Fuel (11 200 ODtonnes/a)		
	Tree Farm at Norman Morrison Bay-Campbell Is.[33] 11 200 ODtonnes/a	Logging Residue from Dry Land Sorts[20] (Average Barging Distance 44 km) 7700 ODtonnes/a	Forest Residue from Landings & Logging Roads[34] (Average Barging Distance 33 km) 3500 ODtonnes/a
Stumpage or Salvage Value of Wood[*2]	$3.13	$3.13	$3.13
Tree Farm Operation	22.69	-	-
Havesting	5.64	-	-
Yarding	-	-	37.68[*3]
Loading	-	-	))) 33.77[*3]
Truck Hauling	12.49[35]	-	
Barge Loading	-	15.90	15.90[*4]
Barging and Unloading	-	44.31[*4]	44.31[*4]
Supervision & Administration	18.95	5.87	5.87
Preprocessing and Hogging to Storage	-	18.47	18.47
Hogging or Chipping to Storage	17.65[35]	-	-
Total Cost of Wood Fuel (10% moisture content) Delivered to a Station Storage Area	$80.55/ODtonne	$87.68/ODtonne	$159.13/ODtonne
		Weighted average $110.01/ODtonne	
Cost of Green Wood Fuel (50% moisture content) Delivered to a Station Storage Area	$44.76/tonne	$48.71/tonne	$88.41/tonne
		Weighted average $61.12/tonne	

TABLE B7-6 - (Cont'd)

*1 Processed wood fuel is assumed to have a 50 percent wet moisture content and does not include drying. Cost estimates are at a 4 percent net discount rate.

*2 Discussions with the B.C. Forest Service indicated that a nominal charge of between \$0.10/m³ and \$1.25/m³ could be applied to tree farms or salvage operation.

*3 Basic collection costs would be the same as Bamfield, but the required forest residue collection would be 3500 ODtonne/a instead of 6000 ODtonne/a.

*4 Barging costs are based on a barge dedicated full time for wood fuel transportation with tug and operator being available and required to make 10 trips per year at a turn around time of 3 days per trip (includes barging cost for 3500 ODtonne/a of forest residues).

economical wood fuel source for Bella Bella appears to be processed fuel from a tree farm operation. The wood fuel cost of approximately \$80.55/ODtonne is based on a sustained annual growth rate of 4.24 ODtonne/ha from a medium growth site with no fertilizing, irrigation or weeding (assuming a 4 percent net discount rate).

(ii) Wood-Fired Thermal Plant Costs

A summary of wood-fired thermal plant costs is listed in Table B7-7. The overall construction cost for a 2 MW wood-fired thermal plant at Norman Morrison Bay near Bella Bella is estimated to be \$8,627,000. Similarly the combined cost of a substation and distribution over 5 km is estimated to be \$687,000.

The fixed and variable costs are summarized in Table A7-2 and Appendix E. The gross unit energy cost is estimated to be 211 mills/kW·h, which is appreciably more than the estimated energy cost from diesel generation in 1990/91.

(b) Wood Gasification-Engine Generation Costs

A summary of plant costs for a gas-fired-engine generator is summarized in Table B7-8. The wood fuel costs are based on harvesting trees from a tree farm on Campbell Island as listed in Table B7-6. The overall cost of a 2 MW wood gasifier and reciprocating engine electrical generating plant at Norman Morrison Bay near Bella Bella is estimated to be \$9,215,000. Similarly, the combined cost of a substation and distribution over 5 km is estimated to be \$687,000.

The fixed and variable annual costs are summarized in Table B7-2 and Appendix E. The high fixed and variable costs are due to the operation of the gasifier. The unit energy cost for this method of generation is estimated to be 240 mills/kW·h.

(c) Coal-Fired Thermal Plant Costs

Coal for a coal-fired thermal plant is assumed to come from the Telkwa coalfield near Smithers, British Columbia. The coal port is assumed to be Ridley Island near Prince Rupert, British Columbia and the coal would be brought by barge to the thermal plant site at Norman Morrison Bay on Campbell Island. The cost of the coal is estimated to be \$46/t F.O.B. Ridley Island. The tug and barge costs are estimated to be approximately \$29,000 per trip. It is assumed that the tug and barge combination could carry 2480 t of coal, the quantity required for 6 months operation of the plant. It is estimated that there is a 16-hour demurrage charge at \$275/h on each trip. It is assumed that a front end loader comes with the barge at a cost of \$75/h for standby and \$113/h when operating. It

TABLE B7-7

BELLA BELLA WOOD-FIRED THERMAL PLANT CONSTRUCTION COST
(k$)

Plant:	Material	Labour	Total
Boiler (including auxiliary equipment and piping)	1973	408	2381
Turbine/Generator (including auxiliary equipment and piping)	1174	81	1255
Feedwater System (including heaters, deaerators, etc.)	220	54	274
Cooling Water System (including pumps and trash screens)	46	10	56
Water Treatment Plant (including chemical equipment storage tanks and demineralizers)	93	27	120
Fuel and Ash Handling (including conveyors and storage silos)	582	145	727
Miscellaneous (including vacuum pumps, air compressors, etc.)	60	33	93
Buildings and Structures	143	48	191
Site Preparation			180
Foundations and Concrete			280
Mechanical			450
Electrical, Instrumentation and Controls			500
Painting and Insulation			150
Vehicles (5 yd^3 loader and truck)			700
Hog Fuel Dryer (installed)			100
Engineering @15%			1170
Subtotal:			8627

TABLE B7-7 - (Cont'd)

Substation:	Material	Labour	Total
Site Preparation and Service	48	98	146
Transformer Position	148	106	254
Circuit Breaker Position	62	incl.	62
Subtotal:			462
Distribution (5 km @ $45,000/km)			225
TOTAL Construction Cost[1]			9314

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[1] Plant capacity is for a total net output of 2 MW. Gross output would be approximately 20 percent greater to allow for unit auxiliary and station service requirements. Annual fuel cost estimates are for the gross plant output.

TABLE B7-8

BELLA BELLA WOOD GASIFIER-ENGINE GENERATOR THERMAL POWER STATION CONSTRUCTION COST (k$)

Fuel Handling and Storage Facilities	550
Fuel Drying Facilities	172
Imbert Powerplant Packages (2 MW)*1	6448
Ash Handling and Disposal Facilities	177
Buildings and Offsite Facilities	191
Land and Site Preparation	180
Civil Installations	280
Mechanical Installations	350
Electrical and Instrumentation Installations	500
Engineering (@ 5%)*2	367
Subtotal	9215
Substation	462
Distribution (5 km @ $45,000/km)	225
Subtotal	687
TOTAL Construction Cost	9902

---

*1 Package based on eight Imbert Powerplant Systems with a heat rate of 17 500 GJ/GW·h, rated at 250 kW (net) and each consisting of:

a dryer and wood fuel feed system,
an Imbert wood gasifer (Type 688),
a cyclone and scrubber gas clean-up system,
a gas cooler and electrostatic filter,
a start-up gas blower, and
two 128 kW spark-gas generator sets.

Gross output would be approximately 10 percent greater to allow for unit auxiliary and station service requirements. Annual fuel cost estimates are for gross plant putput.

*2 The percentages relate to the sum of costs for the first four items in the table.

is expected that the round trip would require 41 hours of travelling time; there would be 16 hours of standby at Norman Morrison Bay plus 8 hours for offloading. The delivered fuel cost is estimated to be $61.45/t. The costs of the tug and loader have been escalated to reflect higher discount rates as summarized in Appendix E, although 4 percent is used here.

A summary of construction costs for a coal-fired thermal plant are summarized in Table B7-9 and a summary of all costs and relevant data are listed in Table B7-2 and Appendix E. The construction cost of a coal-fired thermal plant at Norman Morrison Bay is estimated to be approximately $7,866,000. Similarly, the combined cost of a substation and transmission over 5 km is estimated to be $687,000.

The fixed and variable annual costs are summarized in Table B7-2 and Appendix E. The gross unit energy cost for a coal-fired thermal plant at Norman Morrison Bay is estimated to be 150 mills/kW·h.

7.7 TRANSMISSION

The cost estimate for a 69 kV, 3-phase transmission line from Ocean Falls to Shearwater on Denny Island is summarized in Table B7-10. The cost of the overland transmission line is estimated to be $4,446,000. This cost assumes that the line follows one of the longest routes selected by Reid Crowthers and Associates[5] and that this route, which generally follows tributary valleys, would be less exposed to adverse weather conditions. Part of the route near Ocean Falls follows existing roads.

It is assumed that the diesel station would be dismantled and that the value of the station would be offset by the cost of dismantling. The stationary diesels may be left in case of an outage on the line from Ocean Falls.

The fixed costs and variable costs are listed in Table B7-2 and Appendix E. The gross unit energy cost for transmission from Ocean Falls is estimated to be 100 mills/kW·h.

7.8 PAYBACK PERIOD

An explanation of the term payback period, as it applies in this report, is provided in Appendix C, Section 3. The estimates of payback periods assume a 4 percent net discount rate.

The sizes and installation dates of new generating units proposed in this section have not been optimized. Optimization could modify the results sufficiently to reduce the payback period and make another

TABLE B7-9

BELLA BELLA COAL-FIRED THERMAL PLANT CONSTRUCTION COST (k$)

Plant:	Material	Labour	Total
Boiler (including auxiliary equipment and piping)	1827	378	2205
Turbine/Generator (including auxiliary equipment and piping)	1174	81	1255
Feedwater Package (including heaters, deaerators and pumps)	220	54	274
Cooling Water Package (including pumps, piping and trash screens)	46	10	56
Water Treatment Plant (including chemical equipment and demineralizers)	93	27	120
Fuel and Ash Handling (including conveyors, storage silos, etc.)	554	138	692
Miscellaneous (including vacuum pumps, air compressors, etc.)	60	33	93
Buildings and Structures	143	48	191
Site Preparation			180
Foundations and Concrete			280
Mechanical			450
Electrical, Instrumentation and Controls			500
Painting and Insulation			150
Vehicles (Truck)			250
Engineering			1170
Subtotal:			7866

TABLE B7-9 - (Cont'd)

Substation:	Material	Labour	Total
Site Preparation and Service	48	98	146
Transformer Position	148	106	254
Circuit Breaker Position	62	incl.	62
Subtotal:			462
Distribution (5 km @ $45,000/km)			225
TOTAL Construction Cost[*1]			8553

[*1] Plant capacity is for a total net output of 2 MW. Gross output would be approximately 20 percent greater to allow for unit auxiliary and station service requirements. Annual fuel cost estimates are for the gross plant output.

TABLE B7-10

COST ESTIMATE FOR A TRANSMISSION LINE TO SHEARWATER[*1]
(k$)

Transmission Line (3-Phase, 69 kV, 266.8 kcm ACSR - 52 km @ $85,500/km)[*2]	4446
Submarine Cable (Four - 1-conductor submarine cables, including laying, terminals, switches and surveying)	443
Subtotal:	4889
Substation	1390
TOTAL Construction Cost	6279

[*1] These cost estimates are provided for comparison with diesel and alternative energy sources. The estimates do not imply ownership of any of the facilities from the Shearwater terminus toward Ocean Falls.

[*2] A. Langmuir, System Planning Department, B.C. Hydro, personal communication.

alternative more attractive. The present load growth has been projected over the next 20 years. However, once electrification of existing homes is complete, the load growth may be expected to level off. Reducing the load growth would have a severe impact on new alternatives, particularly those with high capital costs, even if they are capable of providing for large increases in electrical demand (e.g. transmission line from Ocean Falls).

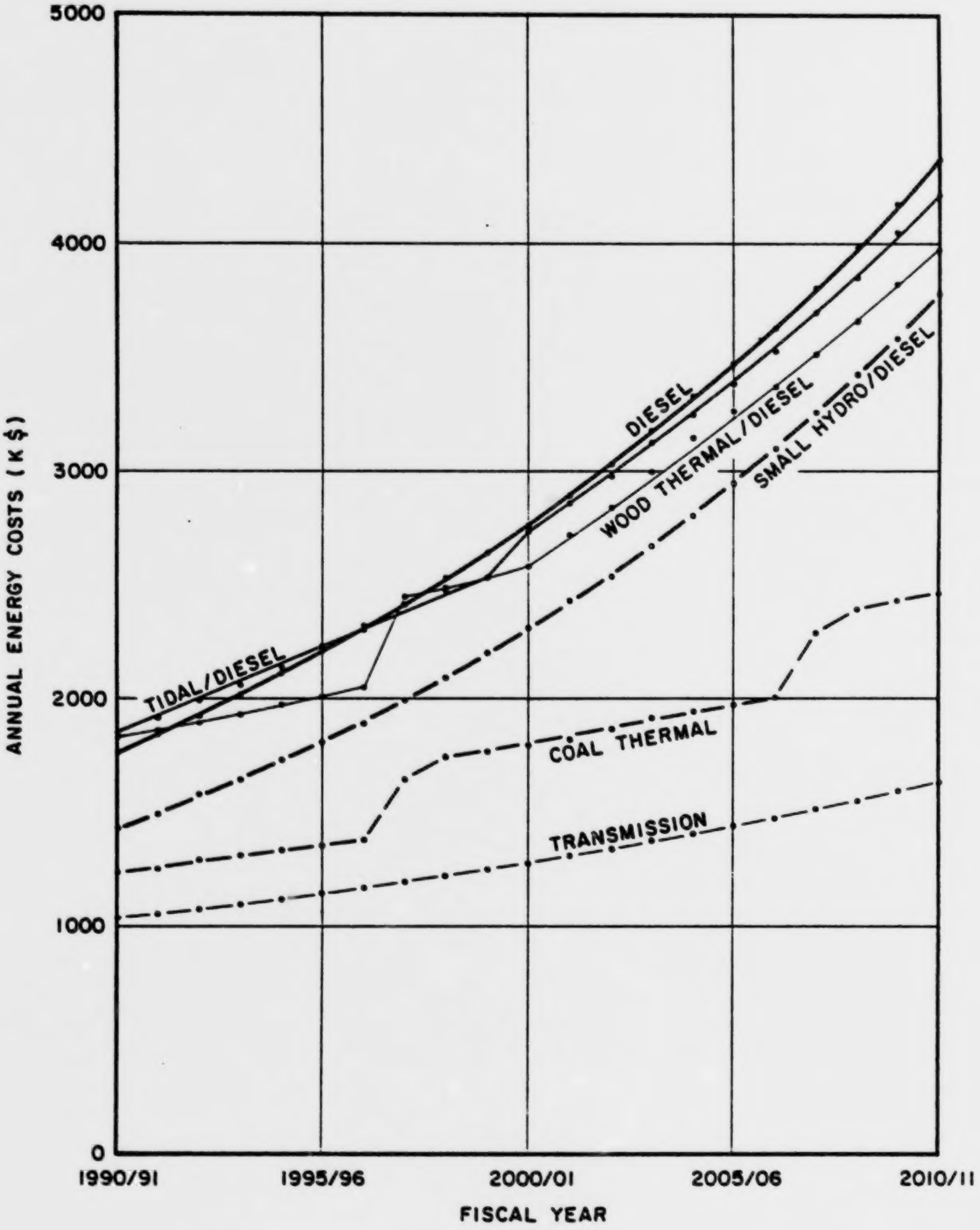
Based on energy costs (Table B7-2) only small hydroelectric, tidal, and coal-fired thermal generation as well as transmission are comparable to diesel generation at Bella Bella. These alternatives were thought to be competitive in view of escalating diesel fuel costs. Their cumulative net cash flows are compared in Fig. B.7-1. The cumulative net cash flow is estimated by taking the investment for the year, adding the interest charge at 4 percent net and subtracting the annual net benefit. The annual net benefit is the difference between the cost of energy from diesel and the cost of energy from an alternative. The time required for these cumulative net cash flows to equal zero is the payback period.

The yearly diesel fuel costs assume that the cost will rise at the rate of inflation through 1986/87 and then escalate at 1 percent per annum (net of inflation) thereafter. It is estimated that the fuel is consumed at a rate of 0.299 L/kW·h and that the cost of lube oil is 2.54 percent of the fuel cost based on 1982/83 fuel consumption rates at Bella Bella. The estimates assume that the growth rates for peak demand and annual energy remain constant at 4.5 percent and 3.7 percent respectively through the period 1990/91 to 2010/11. The estimates also assume that new 600 kW diesel generating units would be added in 1989/90, 1994/95, 1998/99, 2002/03, 2005/06, 2008/09 and 2010/11. Although units of 1000 kW would likely be added in the future, the effect of adding 600 kW units instead is assumed to be insignificant for this cost estimate. Annual costs other then amortization are assumed to increase in proportion to the annual energy.

Small hydroelectric power generation on Walker Lake (1.1 MW) is insufficient to meet either the peak demand or the annual energy of Bella Bella. It is likely that a small hydroelectric generating facility at this location could be base loaded. It is assumed that small hydroelectric generation could provide approximately 75 percent of the energy in 1990/91 and that this proportion would decrease gradually with increasing load. It was assumed that Bella Bella would have 2.4 MW of diesel generating capacity in 1990/91 and that new 600 kW diesel generating units would be added in 1998/99, 2001/02, 2004/05, 2007/08 and 2009/10. For diesel generation, annual costs including fuel costs, but excluding amortization, were estimated each year on the basis of load. For small hydroelectric generation annual costs, including amortization, were held constant over the life of the plant. It is evident from Fig. B.7-1 that, as the cost of diesel fuel increases, the benefit of the small hydroelectric components in the small hydroelectric/diesel system eventually increases. Initially the net benefit from small hydro generation is negative, but by 1998/99 the

FIGURE B.7-1

ANNUAL ENERGY COSTS - BELLA BELLA



savings in diesel fuel begin to pay back the initial investment. The payback period would exceed 20 years, but it is less than the plant life of 40 years.

There is little information on the potential for power generation from a small hydroelectric development at Lakes A, B, C and D (0.5 MW). In particular, the status of a potential diversion is unknown. Therefore, no estimate of the payback period was made for this alternative. It is expected that the annual cost curve for Lakes A, B, C and D would approximately parallel the annual cost curve for Walker Lake, but the annual unit energy cost would be higher. On this basis the payback period would be longer.

Tidal power generation on Hochstader Basin (2.0 MW) would also be insufficient to meet either the peak demand or annual energy of Bella Bella. It is assumed that the tidal generating plant could be essentially base loaded and that the tidal plant could provide approximately 70 percent of the annual energy in 1990/91; the proportion supplied by the tidal plant would decrease with increasing load. It was assumed that Bella Bella would have 3.6 MW of diesel generating capacity in 1990/91 and that new 600 kW diesel generating units would be added in 1994/95, 1998/99, 2002/03, 2005/06, 2008/09 and 2010/11. It was assumed that 7.0 GW·h/a of electrical energy could be produced each year from tidal power. Annual costs for diesel generation, including the fuel cost, but excluding the amortization cost, were estimated each year on the basis of load. For tidal generation annual costs were held constant over the life of the plant. Tidal/diesel generation is less economical than diesel generation alone and this condition remains unchanged even as the cost of diesel fuel increases. Tidal power would not even begin to pay for itself because of the requirement for appreciable supplementary diesel power generation.

Coal-fired thermal power generation at Norman Morrison Bay could be sized to meet any peak demand or annual energy. For this study it is assumed that three 600 kW diesel generators would be left at the diesel generating station to provide black start capability, peaking and emergency power. It is further assumed that new 1 MW coal-fired units would be added in 1997/98 and 2008/09 when the capacity factor reaches 75 percent. Diesel generating units (600 kW) are assumed to be added in 1993/94, 2003/04 and 2006/07 in order to provide peaking capacity. For diesel generation the annual costs, including fuel costs, but excluding amortization were estimated each year on the basis of load. For coal-fired thermal generation only the fuel cost was estimated on the basis of load, the other annual costs were estimated as a percentage of the construction cost (Appendix C). The cost of coal is appreciably less than the cost of diesel fuel. The cost of coal is assumed to remain constant through 1990/91 and then increase at 0.5 percent per annum over the next 20 years. Among the alternatives only transmission and small hydroelectric/diesel generation are more economical than coal-fired thermal generation (Fig. B.7-1). The payback period for coal-fired thermal generation at Norman Morrison Bay is estimated to be more than 20 years.

A 69 kV, 3-phase transmission line from Ocean Falls could supply the load required by Bella Bella. It was assumed that the diesel station would be dismantled and the salvage value would offset the cost of dismantling the station. The annual costs excluding amortization were assumed to escalate in proportion to the increased load. The cumulative net cash flow is summarized in Fig. B.7-1.

Transmission would provide the most economical method of serving the electrical load at Bella Bella. The payback period is estimated to be approximately 10 years.

SECTION 8.0 - DISCUSSION

8.1 INTRODUCTION

The status of the diesel generating station at Shearwater (Bella Bella) was examined based on a 1990/91 load in order to compare small hydroelectric, tidal, wind and thermal generation (wood, wood-gasification and coal) as well as a transmission line.

8.2 DIESEL

The present diesel generating station consists of five units with a total capacity of 3 MW and one 600 kW diesel generator is scheduled to be added to the plant in 1989/90. Two of the present diesel units and the future addition are mobiles which permit easy replacement for major overhauls and repairs as well as easy addition when new units are required.

The gross unit energy cost for the diesel generating station in 1990/91 is estimated to be 158 mills/kW·h. The rapid escalation in the cost of diesel fuel which began in September 1980 has seen the price more than double in two years. The price is presently unstable because of the recession and it is not expected to undergo a sustained rise for the next few years, then it is assumed to rise at one percent per annum (net of inflation). This rise combined with continued load growth at 3.7 percent per annum would result in a rapid increase in the fuel bill for the diesel station.

The present diesel station is in a location where noise from the station does not have a serious impact on the local residents. Other than using fuel oil, a rapidly depleting resource, the diesel generating station has few adverse environmental impacts.

8.3 SMALL HYDROELECTRIC

A site on the creek draining Walker Lake was selected initially for this study as the most favourable potential small hydroelectric site to serve Bella Bella. Subsequently, it was found that another site on the drainage from Lakes A, B, C and D had been identified in a 1963 report[2] as a potential small hydroelectric site. Therefore, costs have been estimated for both of these sites. However, the 1963 report describes Lake D as draining in both directions, but the topographic map indicates that it drains away from Lakes A, B and C. The effect of removing Lake D from the drainage area would reduce the estimated annual flow toward the proposed powerhouse by approximately 15 percent.

A 1.1 MW small hydroelectric generating station on Johnson Channel at the mouth of the creek draining Walker Lake could provide 7.7 GW·h/a in 1990/91 at an 80 percent capacity factor. This generation assumes that a small dam would be constructed at the outlet from Walker Lake to regulate flow and provide storage. If additional investigation of this site is undertaken it would be necessary to accurately determine the size and distribution of the discharge from the lake. A major disadvantage of the Walker Lake site is the 28.5 km transmission distance to Shearwater (including 1.5 km of submarine transmission).

It may be possible to develop a small hydroelectric site on the creek draining from Lake A on Denny Island. This site could be developed either separately or in conjunction with the site at Walker Lake. A 0.5 MW small hydroelectric generating station, on Fisher Channel at the mouth of the creek draining from Lake A, could provide 3.5 GW·h/a in 1990/91 if operated at an 80 percent capacity factor. In order to obtain the required flow for this generation it is assumed that a small dam would be constructed on Kajusdus Creek at the outlet from Lake D. Similarly, it assumes that a small dam would be constructed across the outlet from Lake A in order to partly regulate the flow. The main advantage of this site is its location on Denny Island 13 km from Shearwater.

Small hydroelectric development(s) alone could not supply the required energy and supplementary diesel generation would be necessary if this alternative was selected. The addition of diesel generation would significantly increase the overall cost of energy from a small hydroelectric alternative at Walker Lake from 109 mills/kW·h to 131 mills/kW·h. The payback period is estimated to be more than 20 years. The cost of hydroelectric generation from Lakes A, B, C, and D is estimated to be 111 mills/kW·h without adding the cost of diesel generation. The effect of removing Lake D from the drainage would be to increase the unit energy cost by approximately 15 percent. Therefore, it may be economical to develop one or both small hydroelectric sites as alternatives to diesel generation.

The principal environmental impacts of small hydroelectric developments near Bella Bella would be effects on the salmon fishery. The creek draining Webster Lake has small salmon runs. The spawning beds are within 400 m of the mouth of the creek, above that the creek is impassable because of a 12 m waterfall. Kajusdus Creek which drains from Lake D toward Kakushdish Harbour has large salmon spawning runs, but the impact on fisheries resulting from blocking a small tributary near the headwaters is unknown. A lesser environmental impact would be the visual effect of a linear swath cut through the pristine forest in order to provide for the distribution right-of-way from the small hydroelectric site to Shearwater.

8.4 TIDAL

A site for a 2 MW tidal generating station near the entrance to Hochstader Basin on Campbell Island was examined as a potential source of electrical energy for Bella Bella. The annual energy which could be produced by tidal power at this location is estimated to be 7 GW·h based on a 40 percent capacity factor. It would be necessary to have diesel or another form of reliable generation in order to provide electrical power during periods of slack tides. Therefore, because of its intermittent nature, tidal power is relegated to the role of fuel saver and this increases the cost significantly. The gross unit energy cost for tidal power is estimated to be 169 mills/kW·h and this cost increases to 176 mills/kW·h if the supplementary diesel generation is included. Therefore, the overall cost of energy is considerably more than diesel generation.

The environmental impacts of a tidal development on Hochstader Basin would be small. The basin was once the site of a herring spawn and associated fishery; the exact status and potential of this fishery is presently unknown. Similarly, some coho are believed to use this estuary, but again the extent of this fishery potential is unknown. They are believed to be small because they are not exploited by local fishermen.

8.5 WIND

There is no wind monitoring of high sites in the vicinity of Bella Bella. The existing sites are near sea level, but they indicate that a site accessible to winds off the open ocean would be the most suitable for wind generation. A site at the top of Mount Hand (El. 300 m) has been selected as a potential site for a wind farm consisting of four 200 kW horizontal axis wind turbines. Unfortunately, wind is intermittent which results in a moderate capital cost with a low capacity factor. The plant capital cost is estimated to be $4 200 000 and the capacity factor is estimated to be 32 percent. The annual energy is assumed to be 2.26 GW·h and the gross unit energy cost is estimated to be 209 mills/kW·h. The energy available from wind is proportional to the cube of the wind velocity. Therefore, estimates on the cost of wind generation are susceptible to errors in determining wind velocity. There is no data available for Mount Hand and data for McInnes Island, northwest of Bella Bella, was used in this study. Obviously, any further work on wind generation would require monitoring of prospective sites.

Diesel generation or another alternative would be required in order to provide supplementary power much of the time, and all of the electrical power when wind velocities are low. The required diesel generation would increase the cost of a wind/diesel combination by an undetermined amount.

The principal environmental impact of wind generation is the conflict over the land use. Presently Mount Hand is the site of active logging.

8.6 THERMAL

(a) Wood

A wood-fired thermal plant at Norman Morrison Bay could supply a limited amount of electrical energy. Wood waste sources in the area are small and widely dispersed. Therefore, a tree farm on Campbell Island was selected as the most reliable source of fuel for a proposed wood-fired thermal plant. It is not known if sufficient land could be found on Campbell Island which could be dedicated to tree farming.

The estimated gross unit energy cost for a wood-fired thermal plant based on tree farming is 211 mills/kW·h. However, some diesel generation would be required to provide black start capability and supplementary fuel which would increase the energy cost significantly. It is assumed that the size of a wood-fired thermal plant could be increased to a maximum of 3 MW. This is a limit imposed by the space available on the island for a tree farm and it may be somewhat optimistic. A tree farm for a 3 MW wood-fired thermal plant would require approximately 3600 ha. It is estimated that the unit energy cost would rise markedly, tracking diesel costs after the year 2000, because of the restriction on the size of the thermal plant and the requirement for increasing amounts of diesel generation.

The environmental impacts of a tree farm and associated wood-fired thermal plant could be significant. The principal impact would be the land alienation resulting from tree farm operations. In addition, if fertilizing was undertaken, pollutants could enter nearby streams. Tree farming could also increase turbidity in streams and lakes.

It is assumed that the thermal plant would meet all emission standards set by legislation or guidelines. Once-through cooling would result in a temperature rise around the cooling water discharge point, but the effect would be local because of circulation due to the tidal action in the bay and the small size of the plant. Boiler water make up (fresh water) could be a problem because of a lack of large lakes or streams near the proposed plant site. It is assumed that a small stream draining from Mount Hand could be dammed and provide sufficient water for boiler make up. Land alienation for the plant is estimated to be approximately 4 ha for a total land alienation of 3904 ha.

(b) Wood Gasification-Engine Generation

A wood gasification-engine generating plant at Norman Morrison Bay could supply approximately 2.6 MW of electrical power. The plant size is limited by the available quantity of wood and the lower overall efficiency of wood gasification-engine generation relative to conventional wood thermal generation. The project cost ($/kW) of a wood gasification-engine generating plant at Norman Morrison Bay would be less than the cost of a comparable wood-fired thermal plant. However, the gross unit energy cost is estimated to be 240 mills/kW·h, which is approximately 60 percent more than the estimated gross unit energy cost for coal-fired thermal power generation.

In addition, the cost of supplementary diesel generation must be added to the already high cost of wood gasification-engine generation. This would be particularly important in the late 1990s and in subsequent years because the generating capacity could not be expanded; there would be insufficient wood available from a tree farm on Campbell Island.

The environmental impacts of wood gasification-engine generation would be similar to those for wood-fired thermal generation, but there would be additional emissions resulting from the gasification stage.

(c) Coal

A coal-fired thermal plant at Norman Morrison Bay on Campbell Island could provide any amount of electrical energy by increasing the plant size and barging more coal from Ridley Island near Prince Rupert. There is essentially no limitation on the fuel supply and the delivered unit coal cost would decrease from the estimated cost of $61.45/t (1990/91) as the fuel requirement is increased. The gross unit energy cost for coal-fired thermal power generation at Norman Morrison Bay is estimated to be 150 mills/kW·h. This unit cost would decrease as the capacity factor is increased with increasing load. Similarly, the gross unit energy cost would decrease as new units are added. The payback period for coal-fired generation is estimated to be more than 20 years. In this estimate of the future cost of coal-fired generation, it is assumed that the cost of coal would remain constant (relative to inflation) until 1990/91 then rise at a rate of 0.5 percent per annum (net of inflation). An allowance has been made for diesel power generation to provide for peaking and black start capability. It was assumed that approximately 10 percent of the electrical energy would be produced by diesel units. As a result of this addition it is estimated that the cost of coal-fired thermal power generation would be increased to 161 mills/kW·h. It is assumed that new coal-fired units would be added when the capacity factor of the existing units reaches 75 percent.

The environmental considerations would be similar to wood-fired thermal power generation, but there would be more SO_2 emissions, although these would be within legislated limits. Land alienation for the plant is estimated to be approximately 4 ha.

8.7 TRANSMISSION

A 69 kV, 3-phase transmission line could be constructed between Ocean Falls and Bella Bella. It is estimated that the line would require 52 km of wood pole overhead transmission and 1.5 km of submarine transmission. The route selected is one of the longest in order to provide security and some ease of construction. The first 13 km of the line would be along existing roadways[5]. In order to make this line reliable considerable deferred maintenance would be required at the Ocean Falls end. This report provides an estimate for the cost of energy from such a system, but it does not imply who should construct or maintain the facilities.

The gross unit energy cost is estimated to be 100 mills/kW·h which is the most economical of the alternatives examined for Bella Bella. This transmission line could provide for any feasible amount of future growth at Bella Bella. The payback period for the transmission line is estimated to be 10 years assuming no supplementary diesel would be required. Diesel backup may be required for a few years while the security of the line is tested and diesel backup may be desirable in later years for emergency power.

The environmental impact of transmission from Ocean Falls to Bella Bella is principally the visual impact of a linear cut through the trees. Some turbidity could be induced in streams by small slides resulting from construction. Impacts on wildlife are not expected to be significant. Considerable land is alienated by a transmission line, although the line could be moved in the event of some overriding resource conflict.

SECTION 9.0 - CONCLUSIONS

In assessing the alternatives to diesel power generation at Bella Bella alternative fuels (for the diesel generators), small hydroelectric, ocean wave, tidal, wind, solar, wood thermal, wood-gasification, coal thermal, geothermal and transmission were examined. Alternative fuels are not considered practical for the existing generating station and ocean wave and solar technologies are not sufficiently developed. There is no known potential geothermal resource in the vicinity of New Bella Bella or Shearwater.

On the basis of gross unit energy costs the following alternatives were identified as being more economical than diesel power generation (in order of increasing cost): transmission (100 mills/kW·h), small hydroelectric at Walker Lake (109 mills/kW·h), small hydroelectric at Lakes A, B, C and D (111 mills/kW·h) and coal thermal (150 mills/kW·). The gross unit energy cost for tidal (169 mills/kW·h) is estimated to be slightly less economical than diesel power generation (158 mills/kW·h). The gross unit energy costs of wind (209 mills/kW·h), wood thermal (211 mills/kW·h) and wood gasification-engine generation (240 mills/kW·h) are estimated to be appreciably more than diesel power generation.

Of those alternatives which are economically attractive based on their energy costs, only transmission and coal-fired thermal power generation do not require appreciable supplementary diesel generation. It is assumed that 10 percent of the generation in the coal-fired plant is supplied by diesel fuel and no allowance has been made for diesel generation in the case of transmission. The addition of the diesel generation lengthens the payback period. It is estimated that transmission would be paid back in 10 years; coal-fired thermal and small hydro would require more than 20 years. The payback for tidal would probably be beyond the life of the plant. The payback was not determined for the other alternatives because they would be appreciably more than 20 years. The most attractive of the resources located wholly on Denny or Campbell Islands would be small hydroelectric generation from Lakes A, B, C and D. However, cost estimates for this site are very tentative because the site was not visited during the course of the study.

Most of the environmental impacts from the development of alternative energy technologies at Bella Bella would affect the fisheries resource, particularly with the development of small hydroelectric or tidal generation and to a lesser extent thermal generation. Transmission and wind generation would create visual impacts due to the clearing which would be required. These impacts would be small because of the protection provided by guidelines and legislation as well as the small size of the various developments. Any requirement for appreciable mitigation or compensation measures to protect the environment would likely remove an alternative from consideration because of the increased cost.

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APPENDIX A

ALTERNATIVE ENERGY TECHNOLOGIES

A.1 INTRODUCTION

Numerous energy technologies could provide alternatives for diesel electrical power generation in British Columbia. The alternatives and fuel sources which could be applicable to Bamfield and/or Bella Bella are the following: small hydroelectric, wave, tidal, solar, wind, thermal and geothermal. Thermal power generation includes the use of wood waste, wood from tree farms, municipal solid waste (MSW), peat and coal. These sources were examined for conventional steam turbines as well as fuel for gasification processes and subsequent use in reciprocating engines or gas turbines. The use of alternative fuels is examined in Parts A and B of the main text of the report.

A.2 SMALL HYDROELECTRIC

(a) Introduction

The development of small hydroelectric generation began in the late 1800s when many plants were built to meet the needs of individualized communities and industrial facilities.[1] Such plants were by necessity located close to their load centres and were designed for isolated operation.

With the rapid growth in electrical consumption and the development of power transmission, it became feasible to build and interconnect much larger plants. The construction of large-scale hydro and thermal plants in the 1930s and integration of the system reduced the attractiveness of small hydro. In addition the cost of construction and operation of small hydro plants did not compare favourably with the large developments.

However, in recent years there has been a renewed interest in small hydro. This has occurred because of the rapid increase in the cost of fossil fuels, public opposition to mega-projects, conservation of non-renewable resources and environmental issues. Advances in design and material technology have greatly improved the feasibility of small hydro. Government legislation has provided additional incentives.

As a result many small hydro plants have been built where cost compares favourably with the integrated system and other power generation options.

(b) Definitions

Small hydro in B.C. ranges in size from a few kilowatts to an upper limit of 20 MW.[2] This upper limit has been adopted by the B.C. Utilities Commission for licensing purposes in order to distinguish between major and minor projects. A power development of less than 20 MW is not classed as a "regulated project" and does not require a certificate of Public Convenience and Necessity.

In the United States the Federal Energy Regulatory Commission (FERC) considers projects of 25 MW or less to be small hydro. Other definitions for small hydro set the upper limit at 50 MW.[3]

A further criterion for classifying small hydro is the degree of design complexity. Small hydro is generally perceived as being of a simplified design with the limited use of sophisticated and expensive features. It is generally recognized that on this basis small hydro can be classed into three sub-categories.[1,3] Plants above 5000 kW tend to require design and equipment features similar to large projects, but in the range of 500 to 5000 kW which is classified as "mini-hydro", equipment and operating criteria are simplified for economic reasons. For plants below 500 kW, sometimes referred to as "micro-hydro", there is a need for greater simplification and such installations would be very basic in their design concept.

In general terms, differences in the design between small and large-scale hydro result from technical and economic constraints and the type of operating service that is required.

(c) Application

Apart from economic and environmental considerations, the resurgence of interest in small hydro grew with the realization that considerable generating potential existed on many of the smaller rivers previously disregarded or considered to be uneconomic. This prompted a re-evaluation of many sites for development, particularly those with old or abandoned plants which could be redeveloped and where there were existing dam structures which could be readily modified for hydro generation. This approach to small hydro development is being vigorously pursued in the U.S. where many of the waterways have already been developed and modified.

In less developed areas small hydro potential is now seen as a viable energy resource. Remote areas or communities which cannot be economically connected to the integrated system can be served by small hydro generation. On an even smaller scale, single homes, farms and small industrial developments which cannot be connected easily to the local distribution system may find small hydro an economically attractive option.

Small hydro in developing Third World countries is often the main source of electrical energy in remote areas. Small hydro is particularly suitable for limited economies because it does not require large capital investment for project construction and the associated distribution system. The relative design and operating simplicity of small hydro is also well suited for countries which do not have a broad technical base.

Small hydro can be incorporated into multi-purpose installations because of its design flexibility. Typical of these would be irrigation and drainage schemes, flood control reservoirs, industrial and domestic water supplies and recreational water usage, all of which have energy potential which usually is not harnessed.

(d) Technology

Small hydro utilizes the same principles as large-scale hydro to convert the potential energy of water into kinetic energy which is then used to turn a turbine-generator. However, one of the main differences between small and large-scale hydro is the manner by which this is accomplished. Large plants usually develop head (energy potential) by means of a high dam structure which is also used to impound and regulate flows. This type of development is normally only economic on large rivers where substantial generating capacity is available to justify the high cost of the dam and associated structures.

In contrast, small hydro usually involves a relatively simple diversion structure and head is developed by diverting flows from a higher to a lower elevation across a steep gradient. Most plants will be of the "run-of-the-river" type and rely on the normal streamflow except where natural storage is available and can be economically utilized. It follows that for an equivalent flow, high head schemes are likely to be of simpler design and more cost effective than low head schemes.

A very important item of equipment in any hydro development is the turbine. The size and type of turbine is primarily dictated by the available head and flow, but site topography, economic considerations and special constraints arising from multi-purpose functions, also influence the selection of the machine.

In response to the growing small hydro market many turbine manufacturers have improved existing designs and developed new ones which are particularly suitable for special applications. In fact there is a greater selection of turbine designs now available for small hydro than for large hydro. Typical turbines used for small hydro generation are: impulse, reaction and crossflow turbines.[3]

(i) Impulse Turbines

The Impulse turbine has the simplest turbine design. In an impulse turbine a high velocity jet or jets of water are fired at buckets arranged around a wheel which is made to turn. There are two varieties of impulse turbine.

1. Pelton

The Pelton turbine is the most common variety of impulse turbine (Fig. AA2-1). Although simple in concept it operates at relatively low speeds and is expensive to manufacture. Under certain conditions this turbine offers operational advantages, but it is normally economical for only small outputs where the head is in excess of 100 m.

2. Turgo

The Turgo turbine is a variant of the impulse design (Fig. AA2-2). The side entry jet arrangement permits a more economical design than the conventional Pelton turbine (Fig. AA2-3). As a result it is more competitive at heads in the range of 60 to 200 m.

(ii) Reaction Turbines

Reaction turbines have a more complex design in which the entire flow path is in a closed system and under pressure. This design gives rise to two types of turbines, the "Francis" mixed flow-type, in which water enters around the circumference and discharges along the axis and the Propeller-type where water enters and discharges axially. Reaction turbines can be installed either horizontally or vertically, but small units are usually horizontal while larger units are mounted vertically.

1. Francis

Francis turbines consist of a circumferential, spiral casing to distribute the flow, wicket gates, runner and draft tube (Fig. AA2-4). This is the most widely-used type of turbine because of its wide operating head range of 25 to 300 m.

2. Propeller

The Propeller turbine is derived from the propeller-type runner and the design is best suited for low head schemes. There are a number of design types which vary in complexity and cost. Propeller turbines range from

TURBINE TYPES

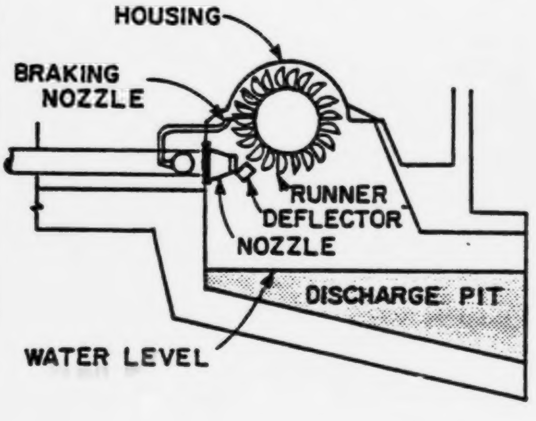

HOUSING
BRAKING NOZZLE
RUNNER
DEFLECTOR
NOZZLE
DISCHARGE PIT
WATER LEVEL

FIGURE AA 2-1
IMPULSE TURBINE (PELTON TYPE)

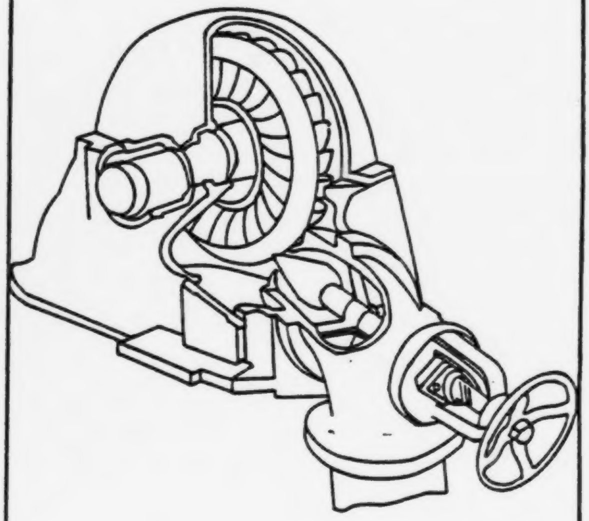


FIGURE AA 2-2
IMPULSE TURBINE (TURGO TYPE)

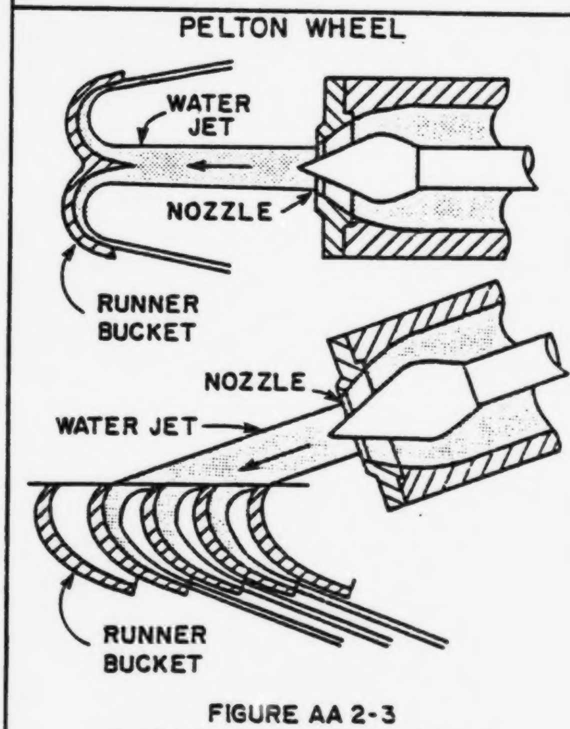

PELTON WHEEL
WATER JET
NOZZLE
RUNNER BUCKET
NOZZLE
WATER JET
RUNNER BUCKET

FIGURE AA 2-3
TURGO IMPULSE TURBINE

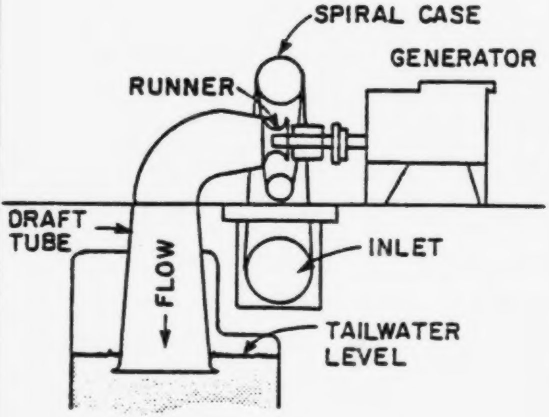

SPIRAL CASE
GENERATOR
RUNNER
DRAFT TUBE
FLOW
INLET
TAILWATER LEVEL

FIGURE AA 2-4
HORIZONTAL FRANCIS TURBINE

the sophisticated Kaplan turbines with a variable pitch runner (Fig. AA2-5) to the simpler fixed pitch turbines which will operate on heads of 3 to 25 m and are particularly suitable for small hydro developments. There are the following main types of fixed pitch propeller turbines:

a. Tube - Tube turbines are horizontally or slant-mounted units with a propeller runner and a generator mounted outside the water passageway (Fig. AA2-6). Allis-Chalmers has developed a standardized "off the shelf" package unit to provide faster delivery and to reduce costs.

b. Bulb - Bulb turbines are horizontally mounted, with either a fixed or a variable pitch runner connected to a sealed generator in the water passageway (Fig. AA2-7). The design was developed by NEYRPIC of France.

c. Rim - Rim turbines have a horizontally mounted propeller runner with the generator mounted on the periphery of the turbine blades (Fig. AA2-8). These turbines were developed by Sulzer-Escher-Wiss AG of Switzerland under the trade name of "STRA-FLO".

(iii) Crossflow Turbines

The Banki or crossflow turbine was developed primarily by Ossberger of Germany (Fig. AA2-9). The design is a variant of the impulse-type and operates by admitting water to the runner through an inlet and guide vane control system. The units are available in standard sizes of as much as 1 MW and will operate on a head range of 5 to 200 m.

Therefore, there is a wide selection of turbines which can be used for small hydro generation, and it is apparent that several different types are suitable for most applications. Selection is primarily based on operating characteristics and careful analysis is required to identify which type of turbine is best suited for the anticipated conditions. Fig. AA2-10 illustrates the potential range of operation of each type of turbine.

The use of non-metallic piping materials can be considered for small hydro applications because large penstock diameters are not required. Polyethylene piping is generally more economical than steel and offers other advantages such as durability, flexibility, low hydraulic losses and ease of installation.

TURBINE TYPES

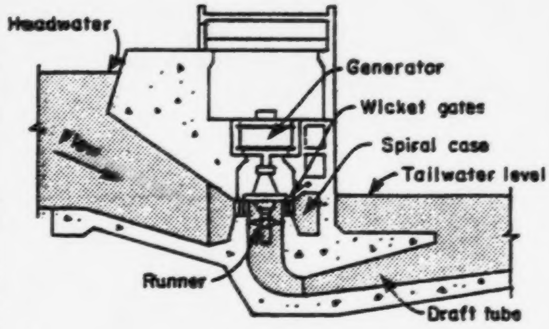

Headwater
Flow
Generator
Wicket gates
Spiral case
Tailwater level
Runner
Draft tube

FIGURE AA 2-5
KAPLAN TURBINE

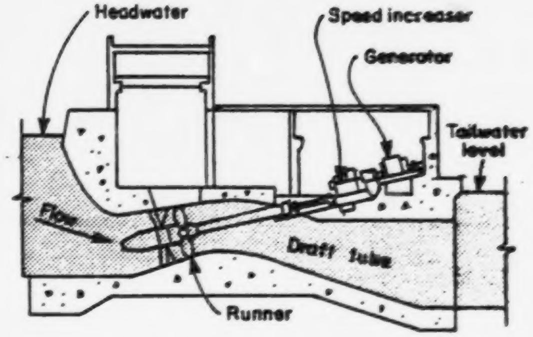

Headwater
Speed increaser
Generator
Tailwater level
Flow
Draft tube
Runner

FIGURE AA 2-6
TUBE TURBINE

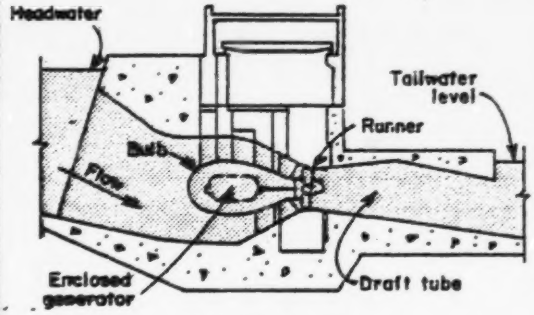

Headwater
Tailwater level
Runner
Bulb
Flow
Enclosed generator
Draft tube

FIGURE AA 2-7
BULB TURBINE

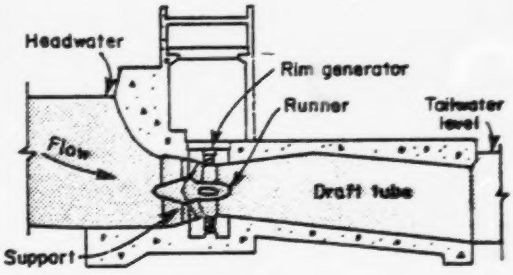

Headwater
Rim generator
Runner
Tailwater level
Flow
Draft tube
Support

FIGURE AA 2-8
RIM TURBINE

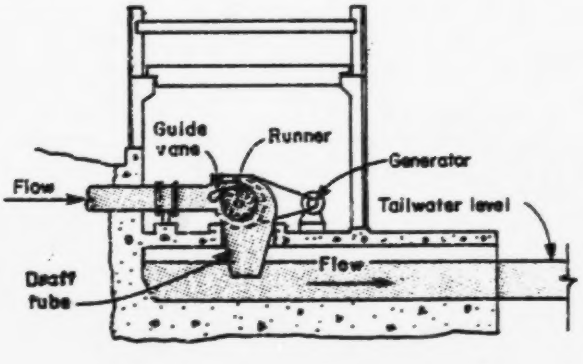
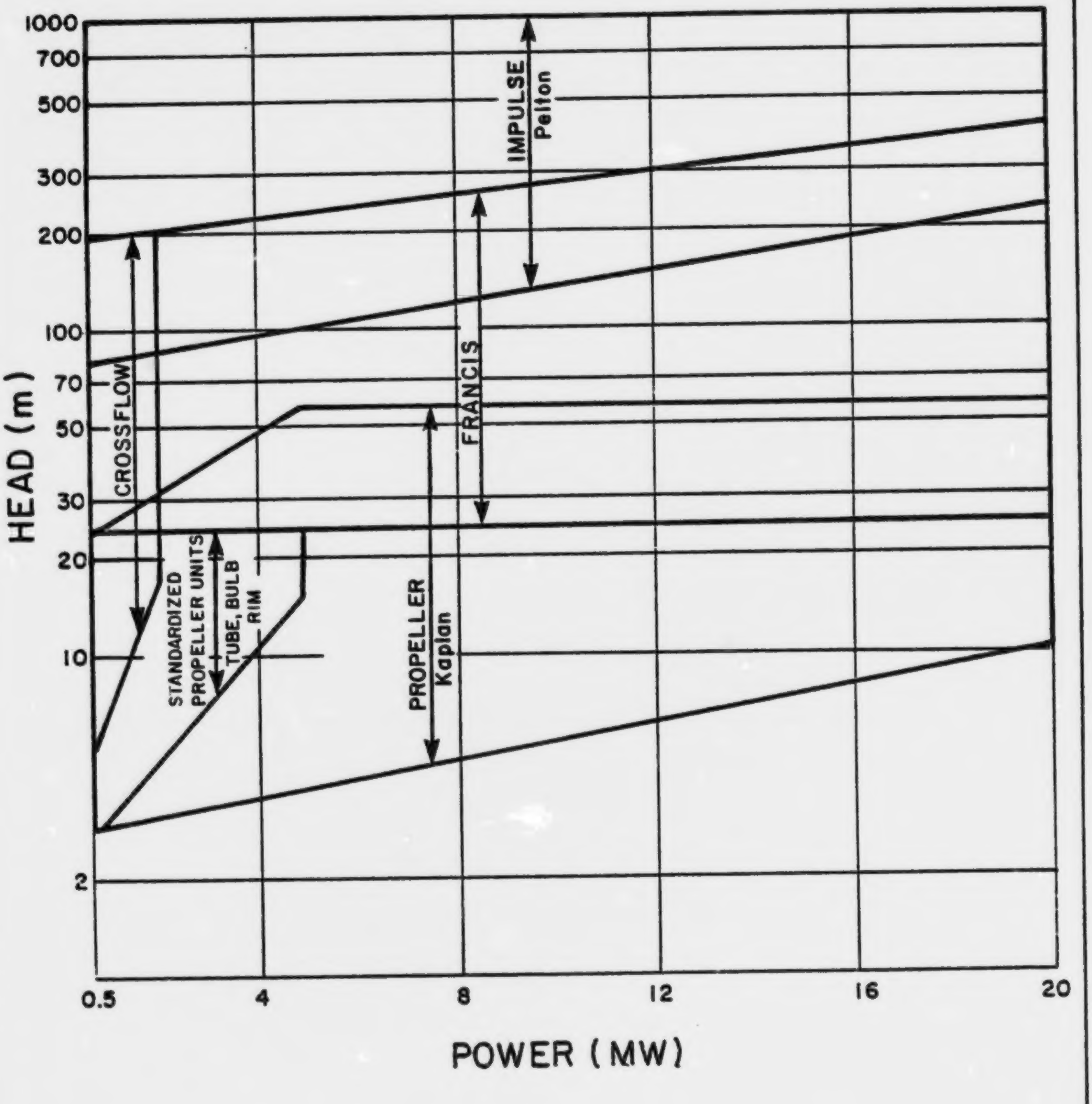

Guide vane
Runner
Generator
Flow
Tailwater level
Flow
Draft tube

FIGURE AA 2-9
CROSS-FLOW TURBINE

FIGURE AA2-10

SMALL HYDRO
DIAGRAM OF TURBINE APPLICATIONS
0.5 - 20 MW RANGE



The development of small hydro has also been facilitated by the introduction of electronic controls. Changes in load demand can be readily accommodated and, with "run-of-the-river" plants, generation can be matched to flow fluctuations. Electronic controls do not significantly increase the cost of a project, but operating costs can be reduced to a minimum because permanent staff are not required.

(e) Layout Concepts

There are many factors which influence the conceptual layout of a project. However, the prime objective is to develop the greatest amount of head (energy potential) for the lowest cost, given the inherent features of the site and the operating conditions.

Potential small hydro sites can be classified into the following general categories:

1. water fall,
2. damsite (existing or new), and
3. natural gradient.

The method of development and technical features will vary considerably because each type of site has specific characteristics. As a general rule economics limits the complexity of development.

Site categories can be subdivided as follows[3] (Fig. AA2-11):

1. Water Fall

   This type of naturally occurring site is very suitable for small hydro development. Such a site usually requires a small dam or simple intake with a short penstock and surface powerhouse. The cost of penstock materials and civil works are usually low. A typical arrangement is illustrated in Fig. AA2-12.

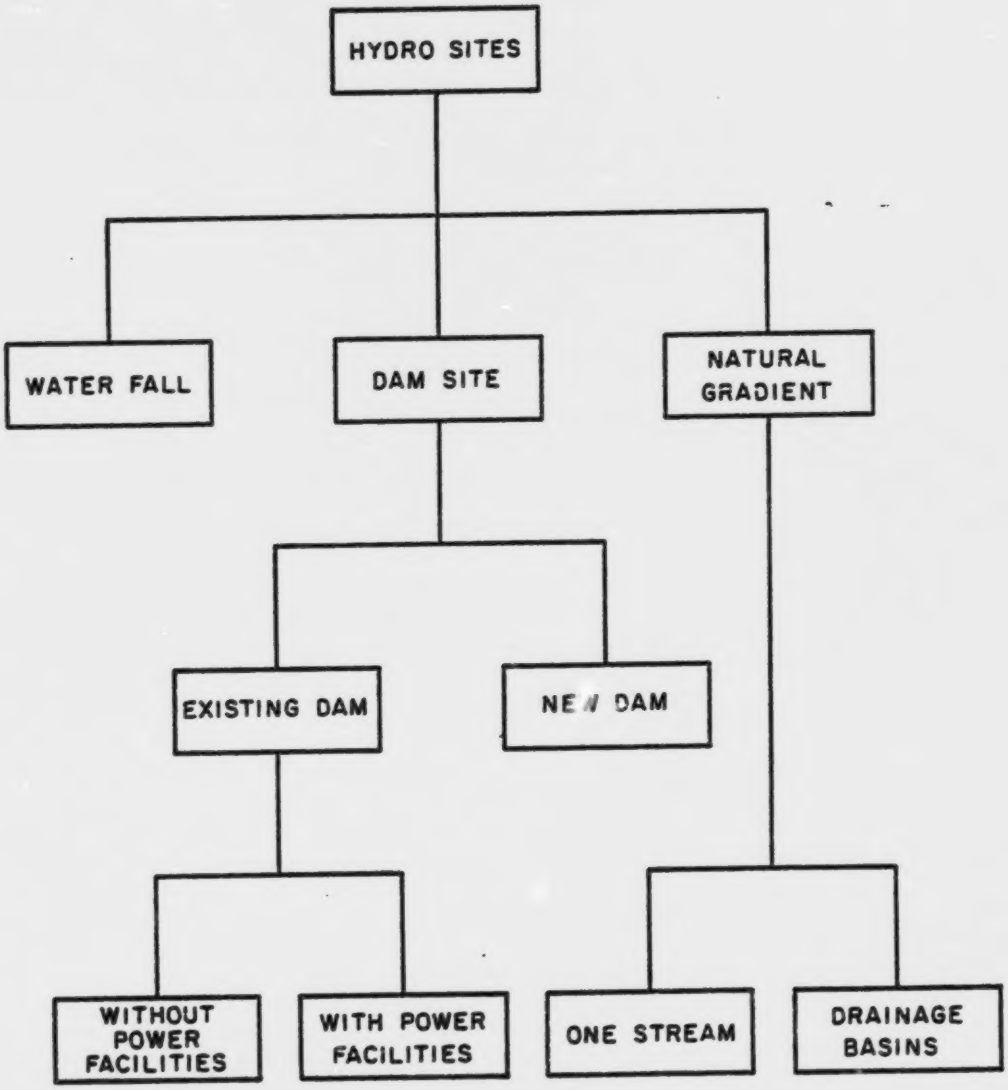
2. Dam Site

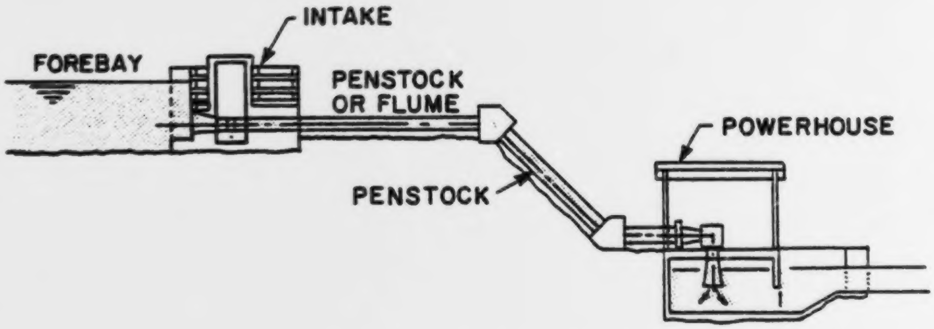
   A narrowing of a stream or river may provide a suitable damsite for low cost development of head (Fig. AA2-13). Such sites can be identified from contour maps, but the feasibility would then depend on the geology and topographic features of the site.

   A site with an existing dam structure may be suitable for small hydro development. Such sites may have an existing or abandoned generating plant and each degree of retrofitting or redevelopment presents different technical considerations and

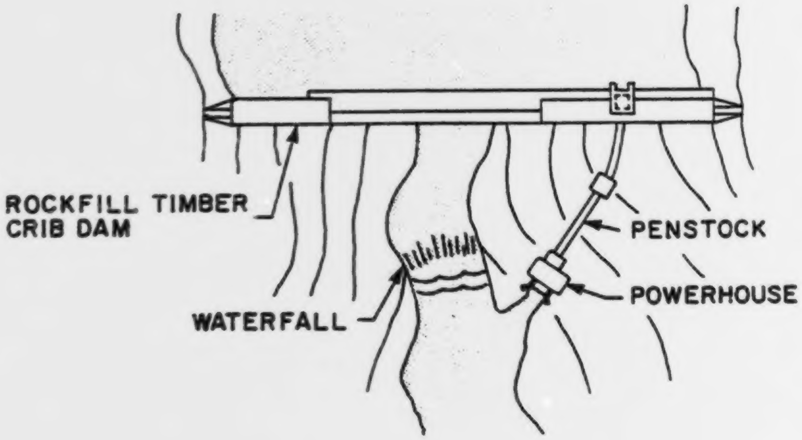
FIGURE AA2-11

CLASSIFICATION OF SMALL HYDRO SITES


HYDRO SITES
WATER FALL
DAM SITE
NATURAL GRADIENT
EXISTING DAM
NEW DAM
WITHOUT POWER FACILITIES
WITH POWER FACILITIES
ONE STREAM
DRAINAGE BASINS


INTAKE
FOREBAY
PENSTOCK OR FLUME
POWERHOUSE
PENSTOCK

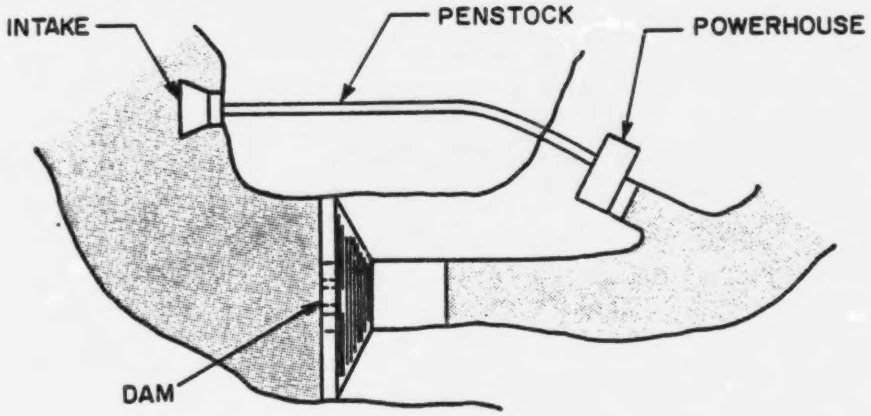
CROSS SECTION


ROCKFILL TIMBER CRIB DAM
PENSTOCK
POWERHOUSE
WATERFALL

PLAN VIEW

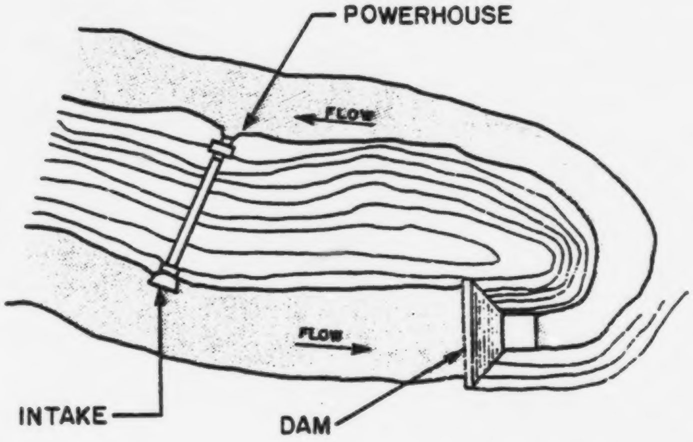
B.C. HYDRO

FIGURE AA 2-12
ARRANGEMENT FOR SMALL HYDRO AT A WATERFALL SITE


INTAKE
PENSTOCK
POWERHOUSE
DAM

B.C. HYDRO

FIGURE AA 2-13
ARRANGEMENT FOR SMALL HYDRO AT A DAM SITE


POWERHOUSE
FLOW
FLOW
INTAKE
DAM

B.C. HYDRO

FIGURE AA 2-14
SMALL HYDRO SITE AT A NATURAL GRADIENT SINGLE STREAM WITH PARTIAL DIVERSION

costs. Sites of this type are usually in well developed areas and would be connected to the local distribution system.

3. Natural Gradient

A small hydro development may utilize favourable topographic and hydraulic gradients along a stream or between two or more streams.

Single-stream site development usually involves the diversion of part of the flow into a low pressure conduit such as an open flume or low pressure piping. A high pressure conduit (penstock) delivers the diverted flow to the powerhouse. The length of conduit used and the head developed is dictated by economic considerations -- steeper gradients are more cost effective. Typical arrangements are illustrated in Figs. AA2-14 and AA2-15.

Two-stream development involves the diversion of the flow from one stream to another stream at a lower elevation (Fig. AA2-16). Connection of two drainage basins could require a tunnel or deeply-buried penstock which would result in high costs and possibly a more significant economic impact.

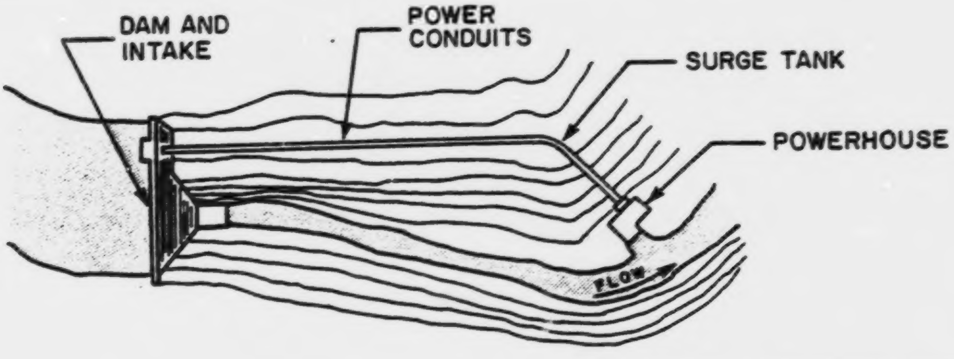
(f) Site Selection and Evaluation

Site selection is usually made by comparing the features of a number of sites, which are within a defined radius from the load centre. It is generally apparent from the preliminary information such as catchment basin size, flow, head and accessibility which site is likely to be the most promising for development. Where a site has already been identified such as a previously developed site (existing dam), this selection process is greatly simplified.

Evaluation of a potential site requires a preliminary estimate of the capital costs and generation benefits which relate directly to the characteristics of the site, the proposed capacity and the amount of generation.

The topography is one of the most important factors affecting the selection and cost of developing a site. The topographic features of a site and catchment basin determine the available head, the flow regime, storage potential, type of development and material quantities required for construction. In addition, the river alignment, bank topography and geologic features will influence the location of principal components.

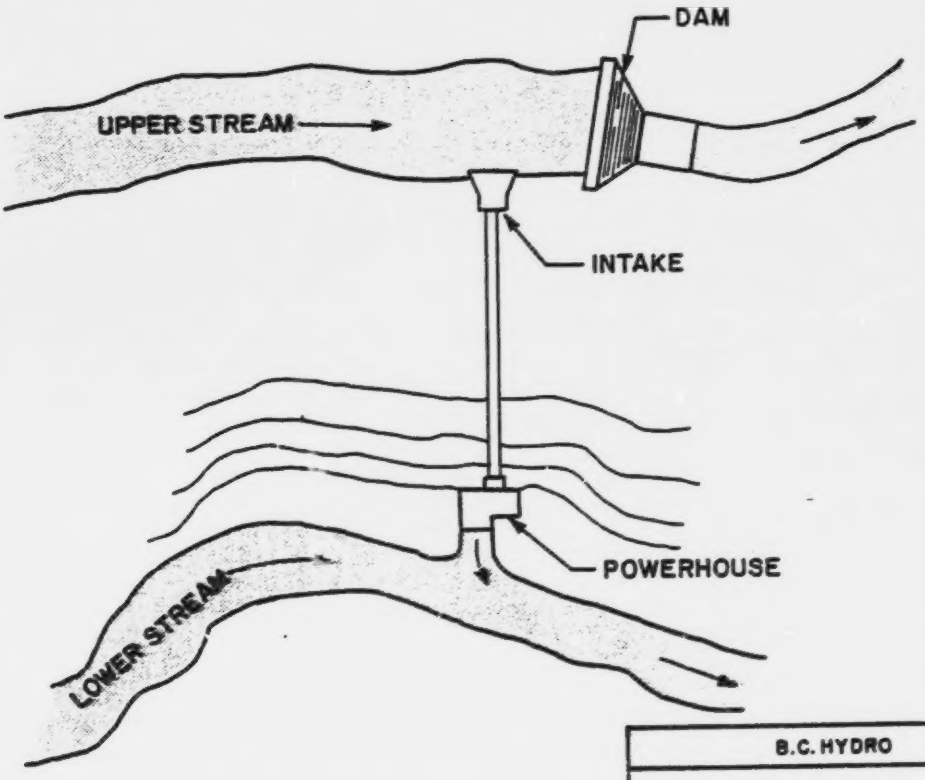
The energy potential of a site is determined from the flow regime of the stream and the available head. However, for many smaller streams, particularly in remote areas, flow records are not available. Therefore, flow data must be estimated and this can be


DAM AND INTAKE
POWER CONDUITS
SURGE TANK
POWERHOUSE
FLOW

B.C. HYDRO

FIGURE AA2-15

SMALL HYDRO SITE
WITH THE GRADIENT
ALONG LENGTH OF RIVER


DAM
UPPER STREAM
INTAKE
POWERHOUSE
LOWER STREAM

B.C. HYDRO

FIGURE AA 2-16

SMALL HYDRO
TWO STREAM
DEVELOPMENT

done by determining the "run off" based on catchment size and annual precipitation or by extrapolation from adjacent gauged streams. Although the mean annual flow can be estimated by these methods, it is also necessary to know the variation of streamflow with time. Seasonal and other flow fluctuation cycles can cause wide changes in the available flow and this is particularly important for "run-of-the-river" plants which cannot rely on storage and flow regulation.

Other factors affecting the evaluation of a site are the transmission distance to the load centre and the ease of access for operating personnel.

(g) Costs

Small hydro development is generally expensive and only under the most favourable circumstances can it be justified. Small hydro development can become economically attractive where costs are reduced by using existing dam structures or where the value of the energy generated is at a premium such as in displacing diesel generation.

Development costs vary considerably and are strongly influenced by site features. However, it is generally recognized that compared to large-scale hydro, equipment and engineering represent a much larger proportion of the total cost, but civil costs are a smaller proportion, A typical comparison of cost distribution is illustrated in Fig. AA2-17.[3]

A.3 WAVES

(a) General

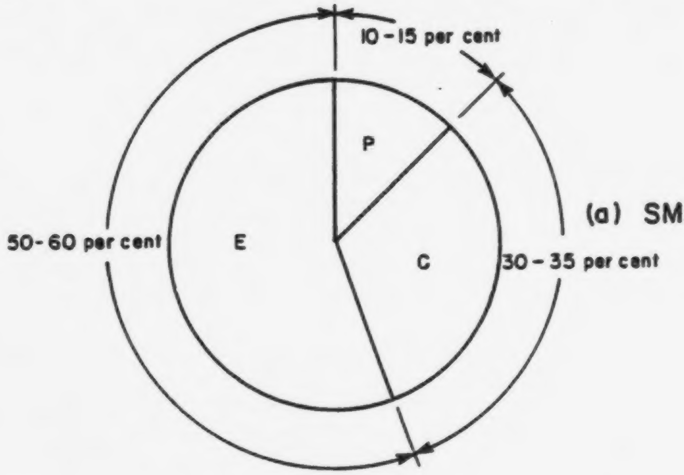
Ocean waves and swells are a result of the action of wind on the ocean surface. Ocean waves contain a substantial amount of power. Measurements were taken by the National Research Council off Tofino on the west coast of Vancouver Island in 1974.[4] They indicate that the yearly average power of ocean waves at that location is about 35 kW/m of wave front. It is expected that there is considerable potential for wave power along the coast of British Columbia because ocean waves are generally strong between latitudes 40 and 60. However, there are no proven, economical ways of harnessing the power of the ocean waves.

(b) Development Concepts

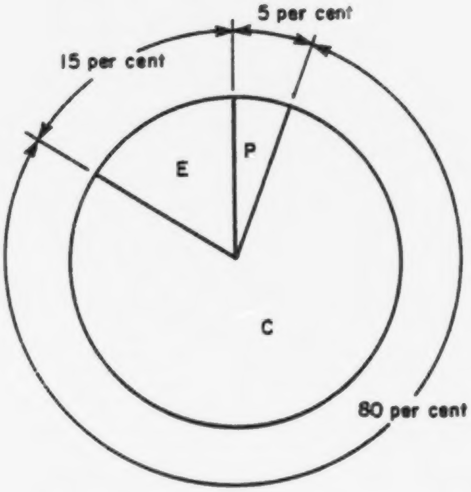
Several countries, including the United Kingdom, Japan, Sweden and France have been conducting wave power research. Many techniques to extract useful power from waves are being investigated.[5] These techniques include oscillating vanes (Salter Duck), undulating

FIGURE AA 2-17

COMPARISON OF THE COST DISTRIBUTION BETWEEN LARGE AND SMALL HYDRO CONSTRUCTION



(a) SMALL HYDRO COST



(b) LARGE HYDRO COST

P - ENGINEERING AND MANAGEMENT
C - CIVIL CONSTRUCTION AND EQUIPMENT INSTALLATION
E - EQUIPMENT

rafts (Cockrell raft), focusing of waves into holding ponds by wave lenses (Norwegian proposal), concentration of waves by refraction over a curved surface (dam-atoll of Lockheed, U.S.A.)[6] and the compression of air by an oscillating water column (Japanese and British). The dam-atoll and oscillating water column concepts appear to be the most promising of these techniques. A dam-atoll consists of a dome-shaped structure which is anchored just beneath the ocean surface (Fig. AA3-1). Waves are concentrated toward the centre of the dome by refraction and they are guided by a chute to a turbine which extracts the energy. In an oscillating water column wave energy device, the water level changes, which are produced by an incoming wave in an enclosed air space, create alternating suction and compression of air (Figs. AA3-2, AA3-3). A valve system converts this alternating air pressure into a unidirectional air flow through an air turbine which produces useful power.

(c) Constraints to Development

At the present stage of development all wave energy schemes involve large structures and high capital costs. A 1 to 1.5 MW dam-atoll structure is estimated to be 80 m in diameter and similarly, a proposed 4 MW oscillating water column is estimated to be 256 m long, 34 m high and 31 m wide.[7] Large structures involve large capital investment and thus high unit cost. Almost all wave power proposals envisage structures in the sea 1 to 2 km from the shore so that power take-offs will involve submarine cables and attendant difficulties. Cost estimates for wave power schemes range from 5¢ to 10¢/kW·h,[7] but these estimates are only preliminary and are considered too optimistic.

A utility-type energy supply based on ocean waves would require considerable energy storage facilities because waves are not regular. However, wave energy schemes may become economical as supplements to other sources resulting in fuel saving. No wave technologies have attained commercial viability, although there are some experimental wave energy schemes operating.

A.4 TIDAL

(a) General

The gravitational effects of the moon and sun in conjunction with the rotation of the earth cause regular fluctuations in ocean levels which are known as tides. Tides follow a semi-diurnal cycle as shown in Fig. AA4-1. The period of the cycle is slightly longer than half a day (i.e. 12 hours 20 minutes) due to the transit of the moon in its orbit around the earth. The pattern and amplitude of the tidal fluctuations at any given location are governed by a number of astronomical factors (e.g. the orientation of the earth's

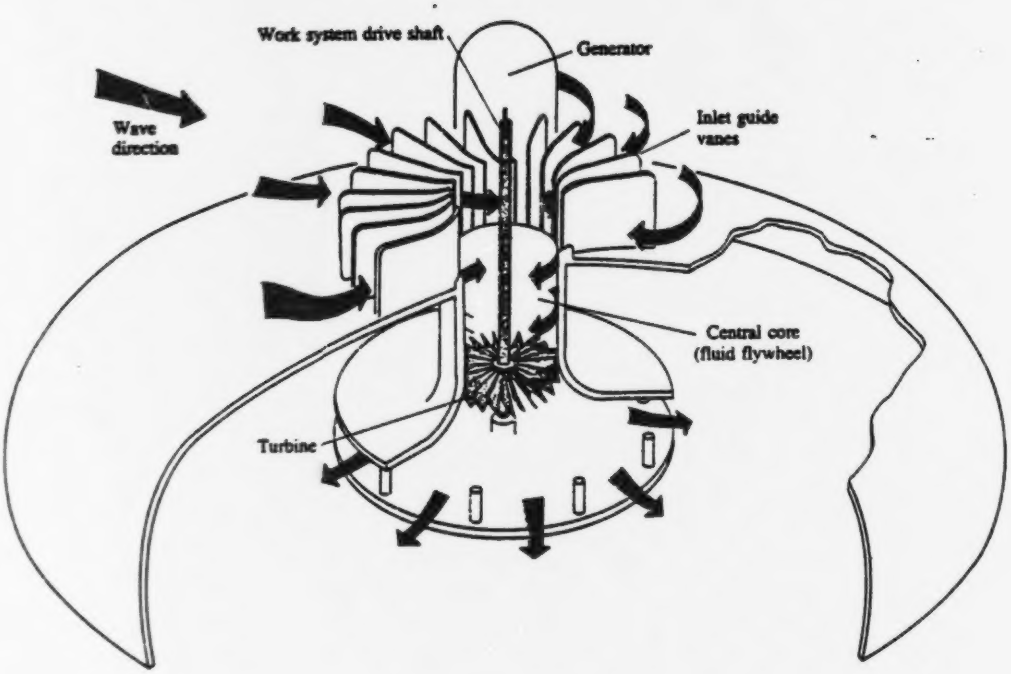

Work system drive shaft
Generator
Wave direction
Inlet guide vanes
Central core (fluid flywheel)
Turbine

FIGURE AA 3-1
DIAGRAM OF DAM ATOLL WAVE GENERATOR

FIGURE AA 3-2

SKETCH OF PROPOSED NEL BREAKWATER - 4 MW MODULE

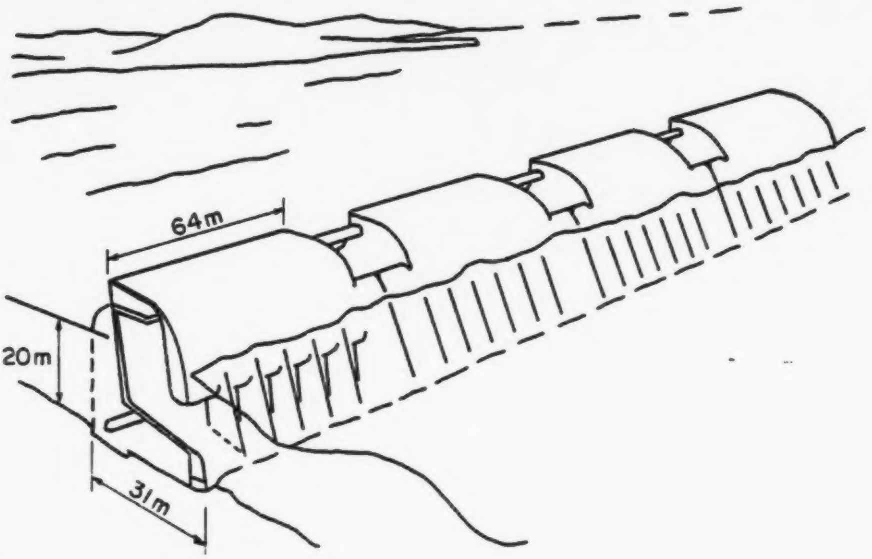
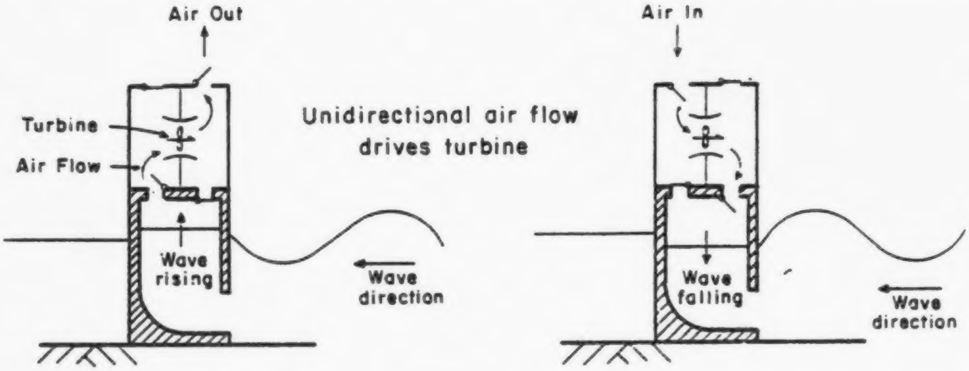
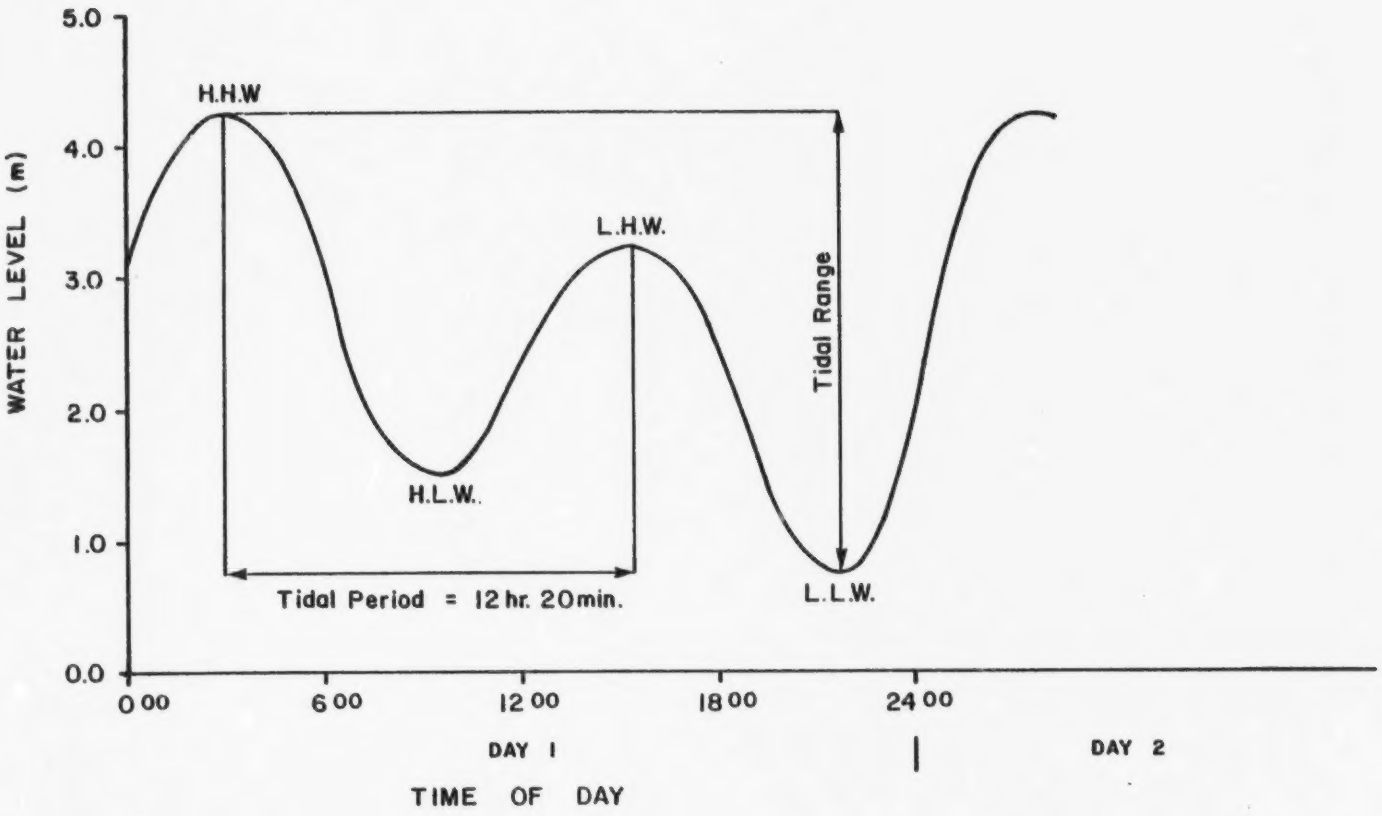


FIGURE AA 3-3

SKETCH ILLUSTRATING THE PRINCIPLE OF OPERATION OF THE OSCILLATING WATER COLUMN WAVEPOWER DEVICE


Air Out
Turbine
Air Flow
Wave rising
Wave direction
Unidirectional air flow drives turbine
Air In
Wave falling
Wave direction



EXPLANATION

HIGH TIDES	H.H.W.	HIGHER HIGH WATER
	L.H.W.	LOWER HIGH WATER
LOW TIDES	H.L.W.	HIGHER LOW WATER
	L.L.W.	LOWER LOW WATER

B.C.HYDRO

FIGURE AA 4-1
TYPICAL DIURNAL TIDAL VARIATION

axis relative to the plane of the moon's orbit and the distance between the earth and moon) and by local geography. The resultant effect of these variables produces complex monthly and seasonal variations in the basic semi-diurnal tides. Typical tidal curves exhibiting these effects are shown in Fig. AA4-2 for several locations on the B.C. coast.[8]

The amplitudes of ocean tides are strongly influenced by local factors, such as depth of water and coastline configuration. In the open sea the tidal range is only about 1 m; however, in coastal areas this range is greatly amplified. On the B.C. coast, the mean tidal range varies from 2 to 5 m. Other areas of the world experience much larger tidal amplification (e.g. Bay of Fundy mean tidal range is 10 to 12 m).

Because tides are governed primarily by astronomical factors and unvarying local conditions, the tides can be accurately predicted for any given location. This predictability is important in the consideration of tidal resources for energy development.

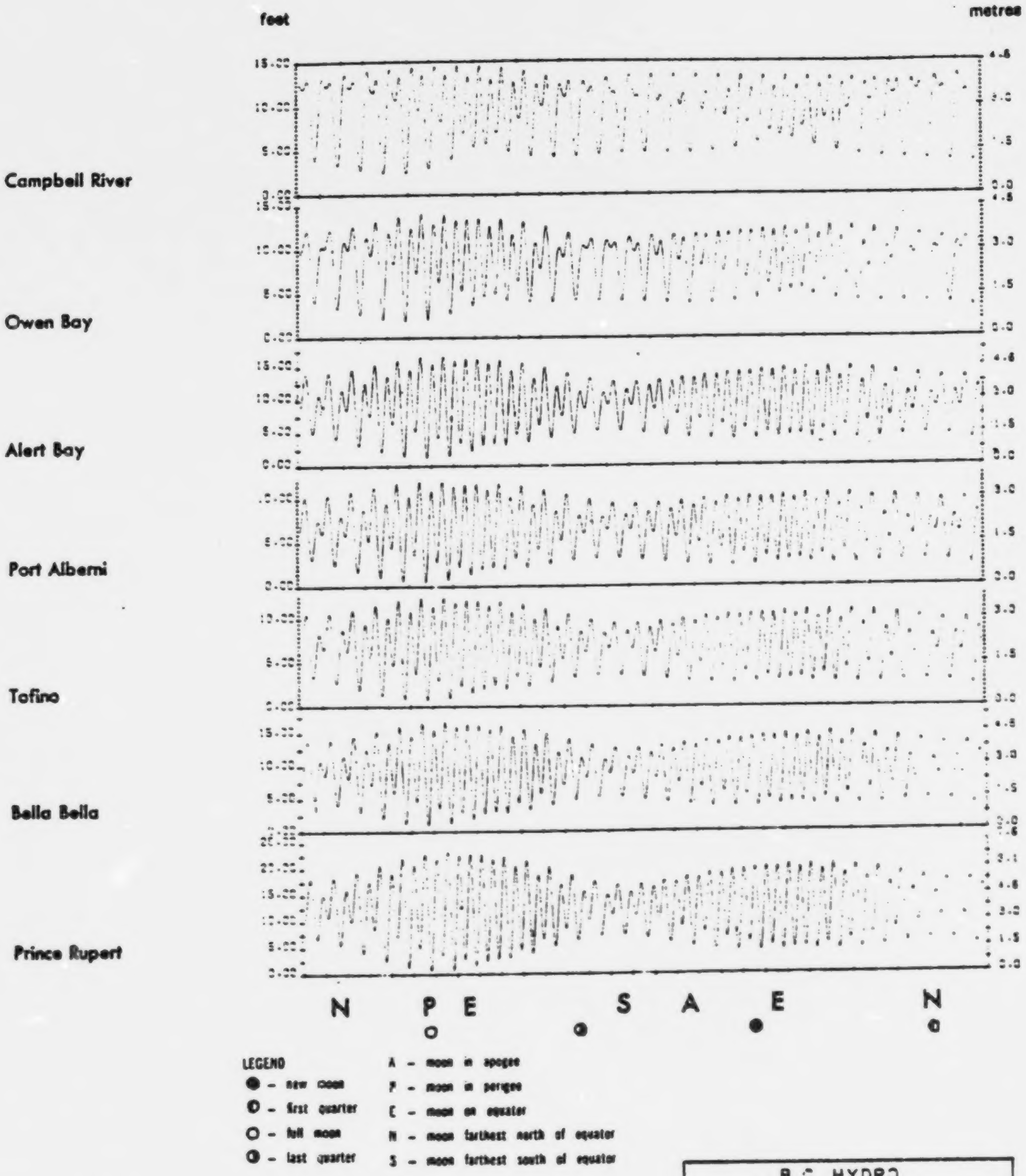
(b) Development Concepts

The ocean tides can be harnessed similar to conventional hydroelectric development of rivers. Generally, sites with high tidal ranges are favoured because the tidal range relates directly to the head available to drive the hydraulic turbines. The unit costs for hydraulic turbines increase with decreasing head.

The most common development concept for tidal energy is the barrage arrangement as shown in Fig. AA4-3A. A typical site for such a development would comprise a large basin separated from the open sea by a short, narrow channel. A barrage of rock or concrete would be constructed across the channel to isolate the tidal basin. Incorporated in the barrage would be hydraulic turbines and sluicegates.

The project may be operated in several different ways, but the most common operation is the single-effect mode as shown in Fig. AA4-3B. The basin is filled on a rising tide by opening the sluicegates. The sluicegates are closed when the maximum basin elevation is reached. The basin is then held at a fixed level until the tide falls sufficiently to permit discharge through the turbines. Turbine operation continues for about 6 to 7 hours as long as sufficient head exists across the barrage. Turbine shutdown is followed by a holding period, after which the cycle is repeated.

Double-effect or two-way generation is also possible, but this requires more complex hydraulic turbines and generally appears to be more costly.



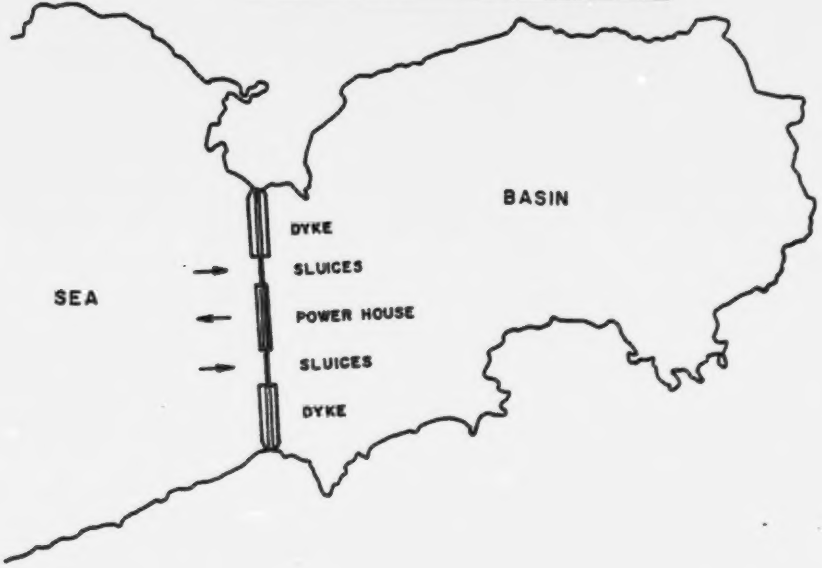
FROM: CANADIAN TIDE & CURRENT TABLES – VOLUME 6 - BARKLEY SOUND & DISCOVERY PASSAGE TO DIXON ENTRANCE, CANADIAN HYDROGRAPHIC SERVICE

B.C. HYDRO

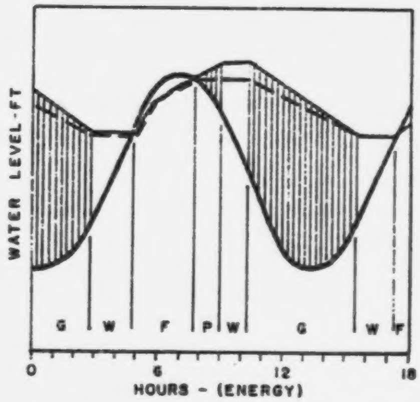
FIGURE AA 4-2

TYPICAL TIDAL CURVES OVER ONE MONTH

A. TIDAL BARRAGE DEVELOPMENT


BASIN
DYKE
SLUICES
SEA
POWER HOUSE
SLUICES
DYKE

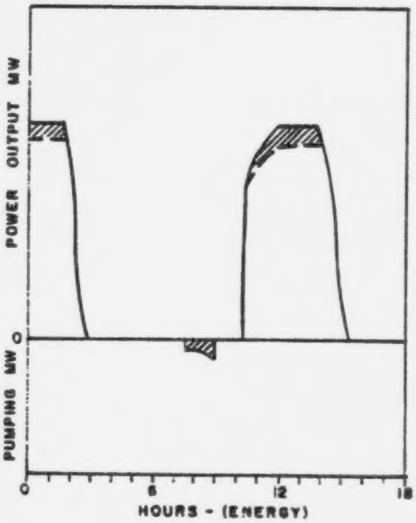
B. SINGLE EFFECT OPERATION



WATER LEVEL VARIATIONS OVER TIME

EXPLANATION

G = GENERATING
W = WAITING
F = FILLING
P = PUMPING
—— BASIN LEVEL - WITH PUMPING
— — BASIN LEVEL - WITHOUT PUMPING
━━ SEA LEVEL



POWER OUTPUT OVER TIME

EXPLANATION

—— POWER LEVEL - WITH PUMPING
— — POWER LEVEL - WITHOUT PUMPING

B.C. HYDRO

FIGURE AA 4 - 3

BARRAGE DEVELOPMENT & SINGLE EFFECT OPERATION

The theoretical energy available from a barrage development is given by the formula:

$$E = 1.97 R^2 A$$

where E is the annual energy in GW·h/a

R is the mean tidal range in m

A is the basin area in km^2

Studies of other tidal developments indicate that single basin, barrage schemes can harness about 20 percent of the theoretical energy. The optimum installed capacity for a site can be estimated by assuming a 30 percent annual capacity factor.

The output from a barrage development can be enhanced by pumping water into the basin at times of low head differential. In effect, pumping increases the effective head for generation. The drawback is the requirement for high capacity pumps or dual purpose turbine/pumps which increase the capital cost.

(c) Existing Developments

To date, there has been relatively little worldwide development of tidal resources. The largest installation is the 240 MW La Rance project in France which began operation in 1966. This project comprises twenty-four 10 MW bulb turbines operating with a mean tidal range of 8 m. The annual energy output is approximately 500 GW·h/a. The La Rance project is designed for maximum operational flexibility, i.e. it can operate in the single-effect or double-effect mode, either with or without pumping in each mode. The Soviet Union has constructed an experimental, 400 kW tidal plant at Kislaya Guba, north of Murmansk. This project was completed in 1968 and its primary purpose was to provide information on tidal plant operation and construction techniques which could be applied to larger scale developments. The Chinese have constructed several small tidal projects over the past 25 years. The most recent project is the Jiang Xia plant, which was commissioned in 1980. Ultimately, this plant will have an installed capacity of 3.0 MW.

Construction of the first tidal plant in Canada is nearing completion in the Bay of Fundy at Annapolis Royal, Nova Scotia. This project makes use of an existing barrage across the mouth of the Annapolis River, and has a generating capacity of 19.9 MW from a single STRA-FLO turbine (Fig. AA2-8). The rated head of the unit is 5.5 m and the rotor diameter is 7.6 m. The energy output is expected to be about 50 GW·h/a.

(d) Constraints to Development

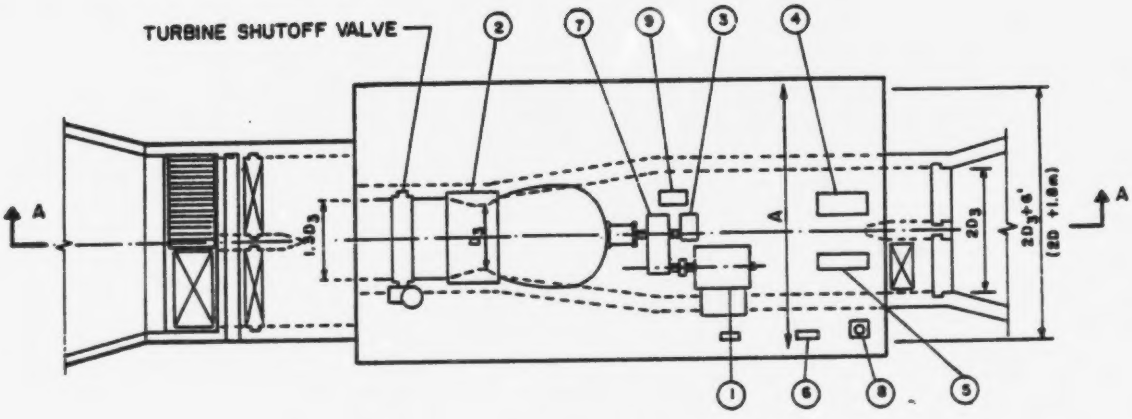
Development of tidal power on either the large or small-scale is technically feasible, but there are a number of significant constraints.

The main constraint to the development of tidal resources is economics. Tidal developments require the use of low head hydraulic turbines such as bulb, rim (STRA-FLOW) and tube types (Figs. AA2-6, AA2-7, AA2-8). These turbines have high unit costs relative to higher head turbine types such as the Francis or Pelton turbines (Figs. AA2-1, AA2-4). This problem is compounded by the fact that unit costs increase with decreasing load. The relatively low tidal ranges on the B.C. coast would require the use of turbines which would have rated heads close to the minimum practical working range for commercial units (i.e. about 2 to 3 m).

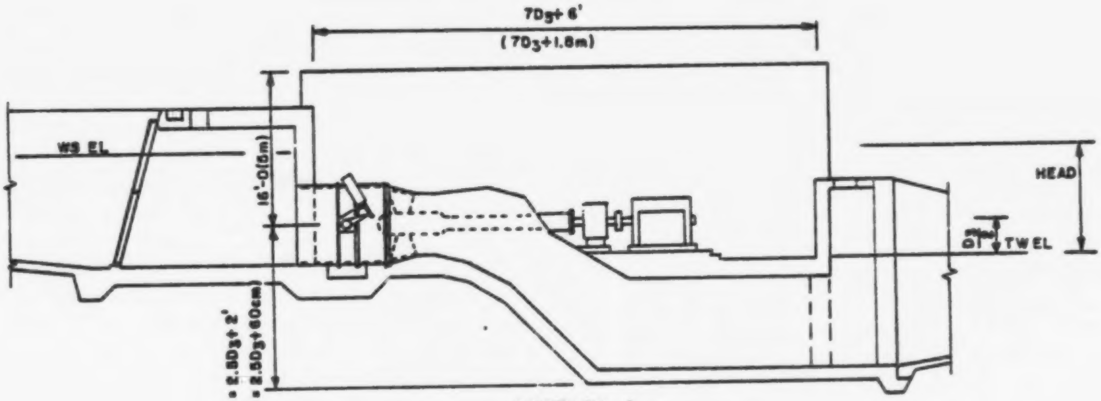
The following example illustrates the unfavorable economics of small, low head turbines for tidal developments. A 1 MW tube turbine/generator having a rated head of 2 m would cost approximately $1.5 million (July 1978, U.S. dollars).[9] By comparison a 1 MW tube turbine/generator (Fig. AA4-4) having a rated head of 10 m would cost about $0.5 million, and a similarly rated Francis turbine would cost about $0.44 million. The high cost of very low head turbines is the most significant single factor which discourages tidal resource development.

Another important constraint to the development of tidal resources is the intermittent nature of the output (Fig. AA4-3). This situation requires the maintenance of back-up generation to supply firm power, thus tidal energy has only secondary value (e.g. fuel savings at diesel powerplants). Modifications to the basic tidal development concept discussed above could improve the continuity of tidal energy output (e.g. the use of turbines capable of two-way generation, multi-basin developments, addition of hydroelectric pumped storage). However, such modifications are not likely to be cost effective for small-scale projects.

Environmental factors are another constraint to the development of tidal resources. Barrage developments would impact on navigation, fish migration and marine ecology in the tidal basin. The significance of these impacts would depend on the specific site being considered. In some cases the impacts could be effectively mitigated (e.g. by the installation of a navigation lock or a fishway), but at an increased cost. Small tidal sites would have to be relatively unencumbered with environmental impacts in order to be considered feasible for development.


TURBINE SHUTOFF VALVE
②
⑦
⑨
③
④
A
A
1.3D3
D3
A
2D3
2D3+6'
(2D +1.8m)
①
⑥
⑧
⑤

PLAN


7D3+6'
(7D3+1.8m)
WS EL
16'-0(5m)
d=2.5D3+2'
d=2.5D3+60cm
HEAD
TWEL

SECTION A

EQUIPMENT

1. GENERATOR
2. TURBINE
3. GOVERNOR
4. GENERATOR BREAKER
5. CONTROL PANEL
6. NEUTRAL GROUND CUBICLE
7. SPEED INCREASER
8. SUMP PUMPS
9. PRESSURE SET

NOTES:

1. ARRANGEMENT AND EQUIPMENT ARE SCHEMATIC.
2. LAYOUT, EQUIPMENT AND DIMENSIONS SHOWN MAY VARY ACCORDING TO SITE SPECIFIC POWER PLANT CONDITIONS.
3. HEAD RANGE 2-15 m (FOR TIDAL SITES ON B.C. COAST, MAXIMUM HEAD 5 m).
4. UNIT CAPACITIES: AT 2 m HEAD - 50 kW TO 500 kW
   AT 4 m HEAD - 100 kW TO 1500 kW
5. MAXIMUM D_3 = 3.1 m.

*FROM: "RECONNAISSANCE EVALUATION OF SMALL LOW-HEAD, HYDROELECTRIC INSTALLATIONS". TUDOR ENGINEERING COMPANY 1978.

B.C. HYDRO
FIGURE AA4-4
TUBULAR TURBINE
WITH HEADWORKS
PROPOSED CONCEPTUAL
TIDAL POWERPLANT LAYOUT

(e) Technology Development

Conventional low head turbines are available with ratings which appear suitable for implementation in small or large tidal resource developments on the B.C. coast. However, as discussed above the costs of such machines are high and would tend to discourage any proposed development. The development of less expensive, low head turbines would enhance the prospects for tidal resource development in B.C.

In this regard, Nova Energy Ltd. of Dartmouth, Nova Scotia is pursuing the development of a low head turbine concept known as the "vertical axis hydraulic turbine" (VAHT). These machines would be capable of generating at heads less than 2 m and could have substantially lower specific costs than conventional low head turbine types.[10] To date, only small experimental prototypes have been tested and additional development work and demonstration projects would be required before the feasibility of the concept is established. B.C. Hydro and Nova Energy (with financial assistance from Energy Mines and Resources Canada under the Remote Community Demonstration Program) are currently examining the possibility of implementing a VAHT tidal demonstration project at Juskatla Narrows in the Queen Charlotte Islands.

An interesting aspect of VAHT turbines is that they are capable of operating in freestream tidal currents if flow velocities are sufficiently strong (i.e. greater than 2.0 m/s). This feature opens up the possibility of installing VAHT turbines at sites where strong tidal currents are known to occur (e.g. Seymour Narrows). This concept has the advantage that a barrage would not be required, thus there would be capital cost savings and probably reduced environmental impacts. However, the trade-off with freestream units is that power densities are low, thus the turbines tend to be physically large (e.g. for a 1 MW output with a freestream flow of 5 m/s, the turbine rotor diameter would be about 10 m).

The Canadian Electrical Association is planning to sponsor a 1-year study to assess the development status of ultra low head hydraulic machines, including the VAHT. The results of this study should be helpful for further assessing the possible development of small tidal resources on the B.C. coast.

(f) Resource Potential in B.C.

The possibilities for large-scale tidal developments on the B.C. coast were examined in a 1977 overview study by the Hydroelectric Design Division of B.C. Hydro.[11] This study identified 13 potential sites representing an estimated annual energy potential of over 13 000 GW·h/a. However, all of these sites were judged uneconomical in relation to other generation options available to B.C. Hydro (e.g. hydroelectric resources, coal-fired thermal). Consequently, no follow-up studies were undertaken.

To date, there has been no comprehensive assessment of the potential for small-scale tidal development in B.C. As noted above, preliminary studies are being conducted by B.C. Hydro (with support from Energy, Mines and Resources Canada) to examine the Juskatla Inlet site in the Queen Charlotte Islands and to identify potential sites in the Bamfield and Bella Bella areas.

The evaluation of tidal resources depends on a number of site specific factors, thus it is difficult to generalize on the resource potential. Local factors which must be considered in site evaluation include: mean tidal range, basin area, water depth, channel width, transmission distance and environmental constraints.

A useful procedure has been developed for preliminary comparison of the energy costs of different sites. This procedure involves computing a cost parameter defined as follows:[11]

$$C = \frac{LH^2}{E}$$

where: C is the cost parameter

L is the length of barrage required

H is the height of barrage required

E is the annual energy produced

The cost parameter is approximately proportional to the unit energy cost for a given site, but does not take account of the transmission costs.

A.5 SOLAR ENERGY

(a) Development Concepts

Conversion of solar radiation into electricity is possible in many ways. Solar thermal (power tower) and photovoltaics are two of these technologies which could become viable for utility-scale power generation in the near future.[5] Photovoltaics directly convert solar radiation (both direct and diffuse) into electricity by means of solar cells. In solar thermal technology solar radiation is concentrated on a "receiver" boiler by computer controlled mirrors (Fig. AA5-1). The steam from the boiler is fed to a conventional turbo-generator to produce electricity. Both solar thermal and photovoltaic technologies are technically feasible, but economically unattractive at present.

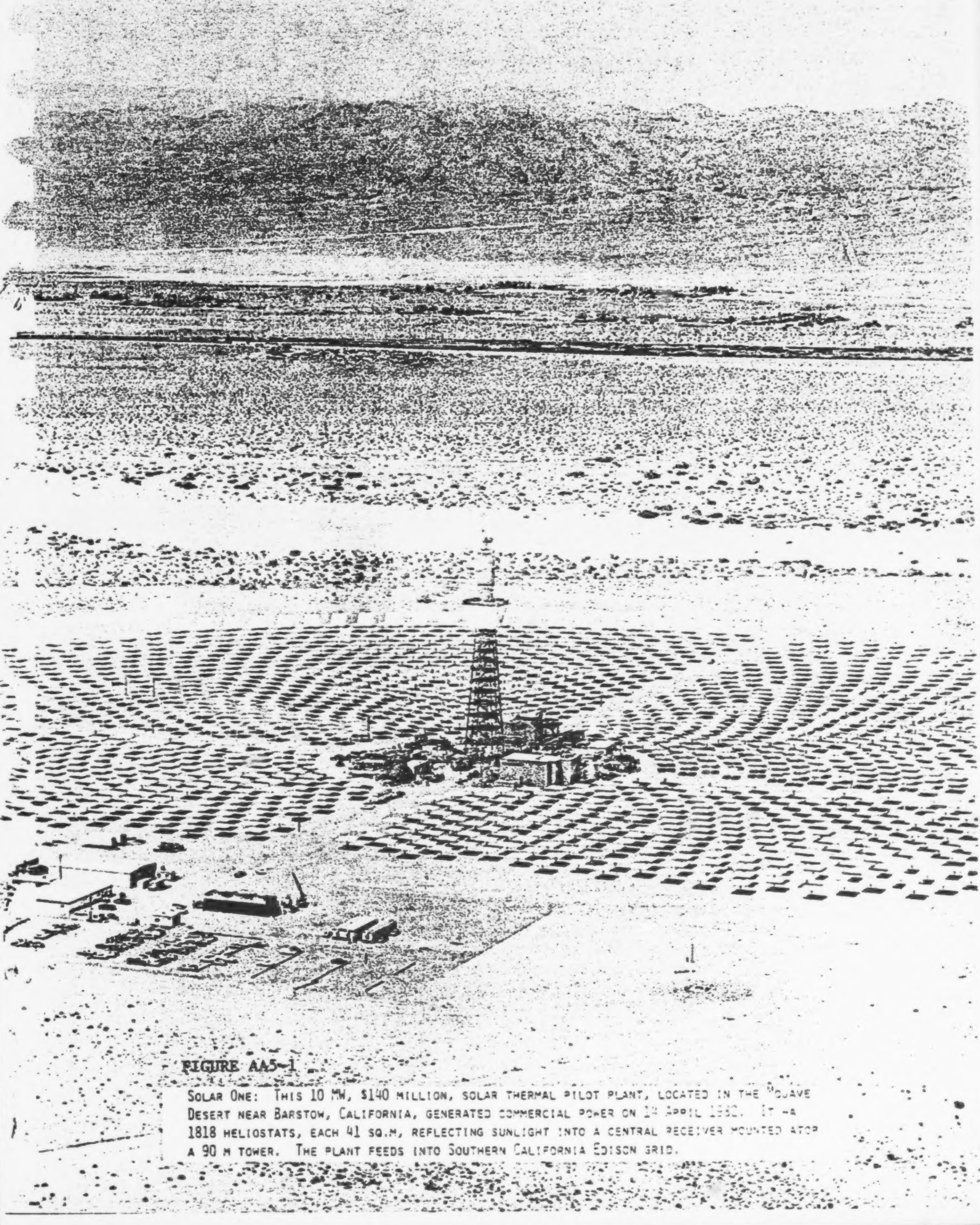


FIGURE AA5-1

Solar One: This 10 MW, $140 million, solar thermal pilot plant, located in the Mojave Desert near Barstow, California, generated commercial power on 14 April 1982. It has 1818 heliostats, each 41 sq.m, reflecting sunlight into a central receiver mounted atop a 90 m tower. The plant feeds into Southern California Edison grid.

(b) Constraints to Development

Considerable research and development in both technologies are taking place in the United States, Japan and in some European countries in order to reduce the costs. Presently, photovoltaics are economically attractive in remote small-scale power applications, but the technology requires about an order of magnitude cost reduction before it becomes attractive for utility-scale applications.

(c) Resource Potential in B.C.

On the average B.C. receives about half as much solar radiation per unit area (~11 $MJ/m^2 \cdot day$) as the southwestern U.S.A.[12] Because a substantial portion (~40 percent) of insolation received in B.C. is diffused, photovoltaics are better suited to B.C. conditions than a solar thermal scheme. Generally, coastal areas in B.C. have more cloud cover and thus the solar radiation in the coastal areas has a higher proportion of diffuse radiation than the average for all of B.C.

Any solar plant would require substantial storage if it was to supply a utility-scale load because of the variability of solar insolation. Therefore, solar plants could be considered only for fuel saving in diesel supplied areas. Smooth terrain and protection from high wind loadings are important factors that will determine structure dependent costs for solar thermal or photovoltaic plants. Considering the low insolation levels, rough terrain, exposure to high winds and high shrub growth rates, both Bamfield and Bella Bella are unsuitable areas for utility-scale application of solar technology. Furthermore, at the present time, both photovoltaic and solar thermal plants are 2 to 3 times more expensive than diesel fuel costs for utility-scale power.

A.6 WIND

(a) General

Electrical energy can be produced from wind by using wind turbines. Annual energy output from a wind turbine is determined using the wind turbine power curve, the mean wind speed at rotor centreline height and the Rayleigh wind speed frequency distribution. The performance and thus the cost per kilowatt-hour of a wind generating system is strongly dependent on the average wind speed. The power which could be extracted from the wind is a function of the cube of the velocity (V^3). For example, the power of a 20 km/h wind is 8 times the power of a 10 km/h wind.[2] In order to make optimum use of the energy output, the wind turbine must be sized to meet the load in off-peak periods.

Wind at any site is variable and unpredictable so that an energy system based on wind will require extensive storage facilities. Thus wind generation in a diesel area is best employed as a fuel saver, but the amount of fuel which could be saved is only about 5 to 25 percent, depending on the wind regime. Due to the problems of interaction between diesel generators and wind turbines it is not desirable to have the wind generating capacity greater than about 50 percent of the peak load in the system.[14] This fact and the short duration of possible wind generation limit fuel saving. However, there appear to be no insurmountable technical problems in connecting wind generation into a diesel system.

If diesel prices increase in real terms in the future, the economics of fuel saving by wind generation could be attractive.

(b) Existing Developments

Most large wind turbines being developed are of the horizontal axis, propeller type with the propeller and the electrical generating equipment placed on top of a tall tower. The vertical axis wind turbine is another type which is being developed by the National Research Council under the Canadian wind power program. Horizontal axis wind turbines need special controls to keep them facing wind and the larger machines are expensive to erect. In contrast, vertical axis machines are insensitive to wind direction and the generating equipment is placed closer to ground level at the bottom of the tower. This placement facilitates plant installation and maintenance. However, in the usual operating ranges, vertical axis machines are generally less efficient compared to the horizontal axis machines.[14] Neither type of machine, in utility sizes, is self-starting and both produce audible noise when in operation.

(c) Development Concepts

In recent years there has been considerable interest in wind power technology and this has given rise to a variety of wind turbine designs. Numerous manufacturers offer smaller wind turbines, up to a few kilowatts, but large wind turbines suitable for utility applications are in the early stages of commercialization.[13] Therefore, reliability and economics are still largely unproven.

Utility-sized wind turbines can be operated only at wind speeds within specified limits which are termed the cut-in and cut-out wind speeds. Below cut-in speed there is no net energy production, whereas above cut-out speed the turbine is stopped to avoid damage. Wind energy is diffuse; therefore, utility-scale wind turbines must be very large. For example, the 4 MW horizontal axis wind turbine built by Hamilton Standard has a tower which is 80 m high, a rotor which is 78 m in diameter, and it requires a wind speed of 55 km/h or 15.3 m/s to reach rated output (Fig. AA6-1). Similarly, the

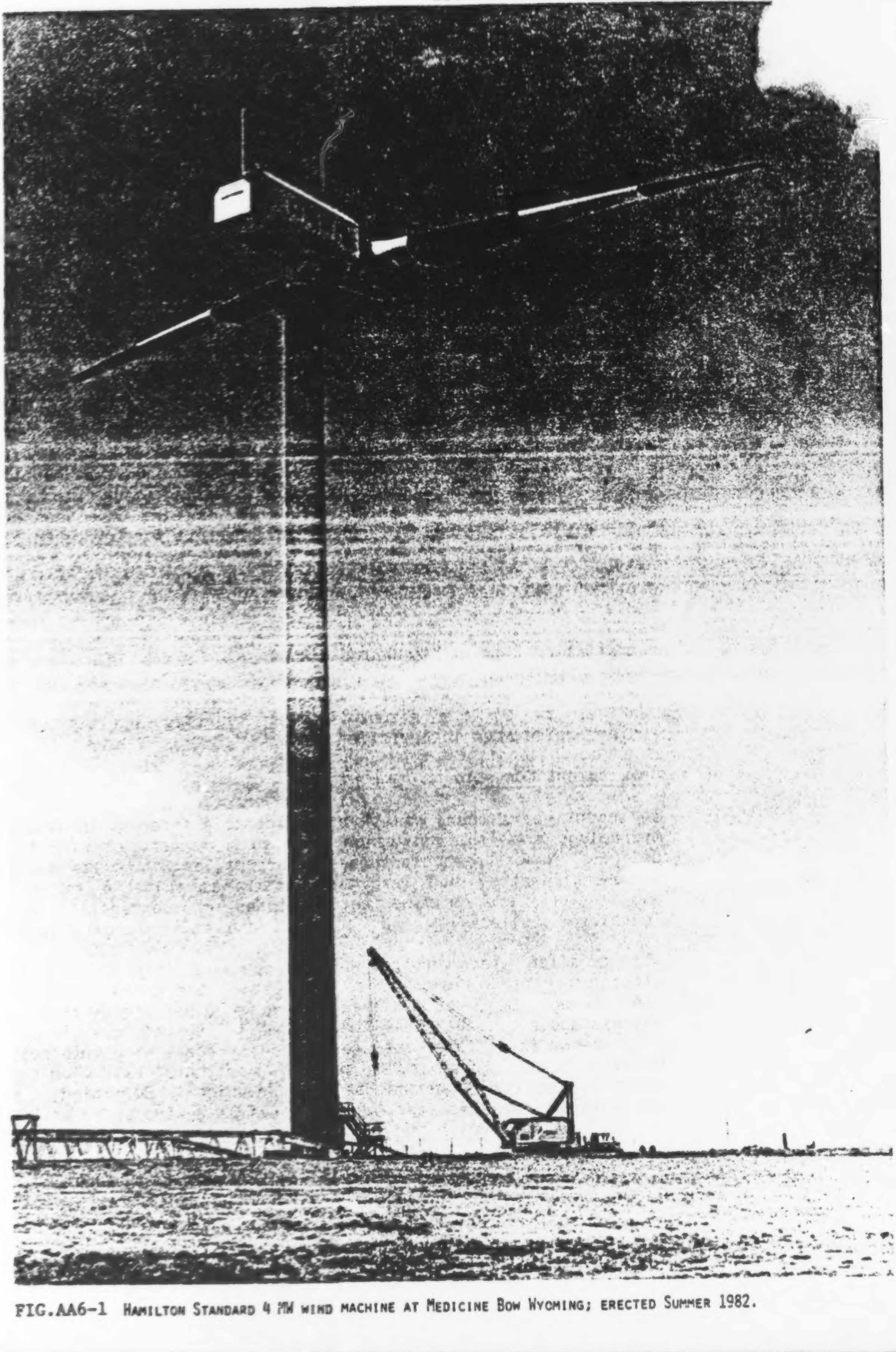


FIG.AA6-1 Hamilton Standard 4 MW wind machine at Medicine Bow Wyoming; erected Summer 1982.

250 kW vertical axis wind turbine built by Daf Indal is approximately 50 m high, the long axis of the rotor is 37 m, and it reaches its rated output at a wind speed of 68 km/h or 19 m/s (Fig. AA6-2). This machine is similar to the 50 kW vertical axis wind turbine at Christopher Point, B.C. which was installed in March 1980 as a joint project funded by the National Research Council (NRC) and B.C. Hydro.

A.7 THERMAL

(a) Introduction

Thermal technologies which are considered potentially applicable for electrical generation at Bamfield and Bella Bella include conventional thermal generation (steam boiler-turbogenerators) using the fuel directly or steam boiler-turbogenerators, gas turbines or internal combustion engines which use gaseous or liquid fuels produced from readily available resources. These available resources could include wood waste, wood from tree farms, municipal solid waste (MSW), peat or coal.

(b) Biomass

(i) Wood Waste

A. Introduction

Wood waste is a general term describing all of the wood residues resulting from forest industry operations. [For this study wet wood waste at 50 percent moisture is assumed to have a heating value of 9300 kJ/kg, whereas oven-dried wood waste at 10 percent moisture is assumed to have a heating value of 16 740 kJ/kg.] Wood waste in British Columbia is produced by the lumber, shake and shingle, veneer and plywood, pulp and paper mills and their associated logging operations as either mill waste or forest residues. Most of it consists of trim ends, slabs, edgings, butts and forest residue.

Mill residue processed as hog fuel can be defined as combustible wood residue in mechanically shredded form which is produced by the forest industry. The mill waste is normally shredded in a "hogging machine" to reduce its physical size for handling and consumption in a steam boiler. It consists primarily of different proportions of sawdust, bark, planer shavings, chip fines, sander dust, plywood trim and/or other wood waste. It is not homogeneous. The proportion of each component varies with the tree species utilized, the manufacturing process, market conditions of various sectors of the

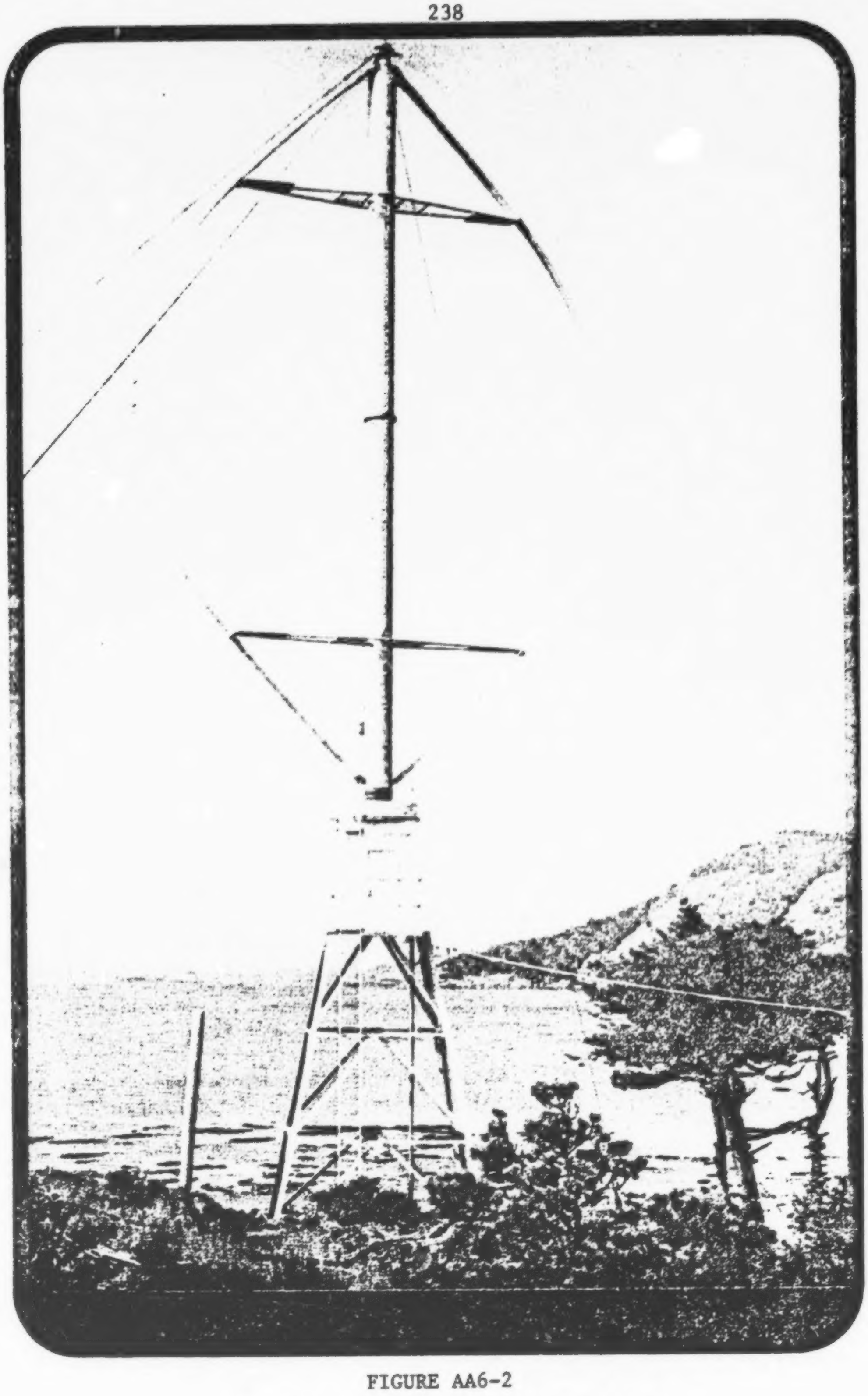


FIGURE AA6-2

VERTICAL AXIS WIND TURBINE

DAF INDAL-50 kW

forest industry and the amount of wood waste utilization practiced.

Forest residues consist of unprocessed logging slash, trees less than 150 mm in diameter, split logs, broken ends and butts, and trees with rotten cores which are left in the forest, along logging roads and at land sorts during logging operations. These residues are between 5 and 15 percent of the log production, depending on the particular site. Other residues consist of driftwood on beaches and unmerchantable timber such as diseased, dead or deciduous trees. An alternative and more secure wood fuel supply for a thermal powerplant could be obtained from a tree farm or energy plantation. Forest residues and wood from tree farms must be harvested, hauled to the generating station and chipped or hogged to size in order to produce a fuel suitable for power generation.

There are no mill residues available as sources of wood waste in the study areas because the forest industry activity in both the Bamfield and Bella Bella areas is primarily logging with little or no wood processing. Consequently, fuel for a wood-fired thermal generating station would be based on forest residues, non-commercial standing timber and/or tree farms. Drift wood and floating debris may be recovered, but it is a widely dispersed wood source and it is not recommended for powerplant operation because of its salt and sand content. Salvage operators selectively recover floating or beach logs for use in the forest industry and they generally leave lower quality material for potential wood waste fuel recovery.

Forest residues could conceivably be collected during or after the logging operation and transported to a generating facility for conversion to usable fuel. Similarly, a stand of non-commercial timber could be dedicated and converted to a tree farm for fuelling a generating station. Estimation of the quantities of wood fuel available from forest residues or tree farms would depend largely on the specific forest region, type of trees, age of the timber stand, nature of the terrain and the utilization standards in force. Over the years, several independent studies have indicated that unharvested forest residues range between 10 and 26 percent of the allowable cut for coastal regions. With current close utilization standards and better forest management this range has decreased to between 5 and 15 percent of the cut.

Processed wood waste could produce varying amounts of power depending on the method used for electrical generation. The various methods which could be used are as follows:

1. The wood could be used in a conventional steam boiler supplying steam to a condensing turbine generator.
2. The wood could be used in an atmospheric fluidized bed unit which could similarly supply steam to a condensing turbine generator.
3. The wood could be used for wood gasification and the product gas could be used in either a steam boiler or a gas turbine-generator.
4. The wood could be used for wood gasification and the product gas could be used in a dual-fuelled or "low-Btu" gas-fired reciprocating engine generating unit.

The technique of using wood waste to fuel steam generators is well established. The use of wood waste as a fuel for pyrolysis or other gasification system is not as well known or as well developed. Wood gasification is a process which shows much promise in the art of converting waste products such as wood waste, municipal solid waste, sewer sludge and other biomass resources into usable combustible gases.

Gasification of wood waste, and the use of the producer gas in a gas turbine or an internal combustion engine to generate power, has several advantages over the conventional steam cycle plant for additions to a utility generating system. Such a plant could be more economical to build and it would not require licenced steam plant staff to operate. However, gasifier/engine generating systems have lower overall efficiencies than conventional steam turbine generating systems.

The generating capacity of a plant fuelled by wood waste depends on the following factors:

1. The quantity of available wood waste.
2. The efficiency of burning wood waste in conventional steam boilers which is 67 to 70 percent when the moisture content of the wood is approximately 55 percent.

3. The overall efficiency of a steam boiler/turbine generating unit which is approximately 30 percent.

4. The heat recovered from a wood gasification system which is approximately 80 percent of the heat value of the wood waste input to the gasifier.

5. The efficiency of small gas turbines operating close to their rated capacity which is approximately 25 percent when using low to medium Btu gas.

6. The efficiency of reciprocating engines operating on low to medium Btu gaseous fuels which is approximately 30 percent.

B. Wood Waste Fuel Costs

The economics of utilizing wood waste as a fuel for thermal generation of electricity is highly dependent on the cost of delivering wood fuel of suitable quality to the generating station. For a generating facility associated with a wood product industry, the cost of wood waste fuel can be accurately defined. However, a generating station at Bamfield or Bella Bella would have to be based on forest residue or tree farm-derived wood fuel.

Several studies conducted in British Columbia and the U.S. Pacific Northwest have indicated costs of recovery of logging residues ranging from $23 to $76 (Canadian dollars) per OD tonne.[15,16,17,18,19] These figures inflated to March 1984 Canadian dollars indicate an average cost of $71/ODtonne for recovery of forest residues at the time of logging (single-entry) and an average cost of $66/ODtonne for second pass (double-entry) residue recovery (excluding transportation costs). These double entry costs do not agree with the costs from an ENFOR study conducted by Paul H. Jones (Table AA7-1).[15] Lighter equipment can be used on second pass residue logging operations, thus reducing the overall cost. Transportation costs of $21.60/ODtonne were estimated for a one-way haul distance of 60 km. The wide range of these costs makes it difficult to evaluate energy projects based on forest residue fuel.

The U.S. Department of Agriculture-Forest Service commissioned a series of studies which were completed in September 1983.[20,21,22] These studies examined the operating costs of harvesting logging residues for use as energy and the studies were based on a typical Pacific Northwest Region forest. The studies specifically

TABLE AA7-1

ON-TRUCK COST SUMMARY WOOD BIOMASS[*1]

(March 1984 Canadian Dollars per ODtonne)

	Logging Residues		Alder Stands	
	Single Pass[*2]	2nd Pass	Skidder	High Lead
Yarding	$30.53	$82.13	$24.60	$38.38
Loading	23.32	15.90	7.92	7.92
Supervision and Administration	7.07	5.87	2.97	2.97
On-Truck	$60.92	$103.90	$35.49	$49.27

[*1] Costs based on Enfor Report (Ref. 15)

[*2] No allowances has been made for loss of logging productivity incurred by yarding residues (which would raise the incremental on-truck cost of residues to $111.80/OD tonne).

examined production rates and costs of harvesting forest residues using skyline logging techniques in two timber sales in western Oregon. Paired logging sites were laid out to compare production rates and costs of removing pieces of residue down to 10.2 cm (4 inches) in diameter by 1.2 m (4 feet in length). The logging sites ranged from 3.2 ha to 11.7 ha (8 to 29 acres) and were on steep ground in old growth forests of Douglas fir and western hemlock. The results of this study provide a good indication of the overall and marginal costs of collecting and processing forest residues during a normal logging operation. Table AA7-2 shows the average cost of logging both merchantable logs and forest residue at the same time down to a 20 cm x 3 m (8-inch x 10-foot) log size, down to a 15 cm x 1.8 m (6-inch x 6-foot) piece size and down to a 10 cm x 1.2 m (4-inch x 4-foot) piece size.

The close utilization standard of timber recovery introduced into the British Columbia forest industry in 1966 requires that all trees, living or dead, with a breast height diameter of 23 cm in the coastal regions must be harvested during logging.[16] All of the stem between a stump 30.5 cm high and a 15 cm diameter top must be utilized. The basic cost of logging to a minimum of 20 cm in diameter and a 3 m length is listed in Table AA7-2. The cost is expected to be in the order of $\$55/m^3$ (\$130 per thousand board feet). This cost includes disposal of residue accumulated on the landings and log sorts during logging (approximately 55.6 ODtonne/ha or 17 percent of the gross log scale removed).

The marginal cost of harvesting forest residue down to 10 cm x 1.2 m (4-inch x 4-foot) pieces is shown in Table AA7-3.[20] Basic logging costs including yarding, loading, and hauling an average distance of 15 km (one-way) were estimated to be \$33.59 per ODton (\$37.03 per ODtonne). The incremental cost of recovering forest residues between 20 cm and 15 cm in diameter averaged \$47.76 per ODtonne (\$43.32 per ODton) and recovering forest residue from 15 cm to 10 cm in diameter averaged \$56.88 per ODtonne (\$51.59 per ODton). Additional hauling was estimated to be \$0.36 per ODtonne/km on paved roads, and chipping was estimated to be \$17.65 per ODtonne.

The Forest Engineering Research Institute of Canada (FERIC) has recently conducted a study on the recovery and utilization of logging residues and log sort yard

TABLE AA7-2

AVERAGE HARVESTING COSTS BY CUTTING UNIT, BLACKEYE AND JOULE TIMBER SALES[*1] OREGON[*3]

(March 1984 Canadian Dollars per thousand-board-feet[*2] gross scale, Scribner log rule)

Minimum Size of Piece[*3]	Cutting Unit	Yarding	Loading	Log Hauling	Total Residue Hauling	Total
Blackeye timber sale:						
20 cm x 3 m (8 inches x 10 feet)	1	64.48	17.10	44.47	4.27	130.32
15 cm x 1.8 m (6 inches x 6 feet)	2	76.50	19.91	41.62	5.13	143.16
	3	76.13	19.37	35.38	4.57	135.45
	40	81.66	32.10	42.75	5.33	161.84
Weighted average		$76.91	$21.01	$39.54	$4.96	$142.42
Weighted average (per m³)		$32.59	$8.90	$16.75	$2.10	$60.34
10 cm x 1.2 m (4 inches x 4 feet)	20	75.97	19.02	39.82	5.49	140.30
	30	93.31	23.54	36.92	6.76	160.53
	4	68.22	28.78	38.88	3.71	139.59
Weighted average		$82.33	$22.13	$38.48	$5.81	$148.75
Weighted average (per m³)		$34.89	$9.38	$16.31	$2.46	$63.04
Joule timber sale:						
15 cm x 1.8 m (6 inches x 6 feet)	12	48.41	16.37	53.84	7.05	125.67
	21	39.99	15.01	42.20	6.96	104.16
Weighted average		$43.63	$15.60	$47.24	$7.00	$113.47
Weighted average (per m³)		$18.49	$6.61	$20.02	$2.97	$48.09
10 cm x 1.2 m (4 inches x 4 feet)	11	45.94	16.42	43.70	9.41	115.47
	22	40.16	13.76	47.65	9.30	110.87
Weighted average		$43.07	$15.10	$45.66	$9.36	$113.19
Weighted average (per m³)		$18.25	$6.40	$19.35	$3.97	$47.97

[*1] For all material removed, including all log grades plus residue.

[*2] Conversion factor is 1 thousand-board-feet is equivalent to 2.36 m³.

[*3] Large end diameter in centimetres (inches) by length in metres (feet).

[*4] Costs have been converted to March 1984 Canadian dollars using a 7 1/2 percent inflation factor and $1 U.S. = $1.24 Canadian.

TABLE AA7-3

MARGINAL HARVESTING COSTS, BLACKEYE AND JOULE TIMBER SALES, OREGON

(In March 1984 Canadian dollars per oven-dry ton and tonne)*4

Piece Size*1	Yarding	Loading	Hauling 15 km (9 miles)	Total	Total With 65 km Haul (40 mi) Plus Chipping*2	Previous Total Minus Yarding*3
20 cm x 3 m (8 inches x 10 feet) and larger:						
Blackeye sale	18.66	5.20	9.73	33.59	66.09	47.43
15 cm x 1.8 m (6 inches x 6 feet) to 20 cm x 3 m (7.9 inches x 9.9 feet):						
Blackeye sale	28.39	7.86	9.73	45.98	48.48	50.09
Joule sale	21.59	6.13	12.93	40.65	73.15	51.56
Weighted average	$25.06	$6.93	$11.33	$43.32	$75.82	$50.76
Weighted average (per oven-dry tonne)	$27.63	$7.64	$12.49	$47.76	$83.59	$55.96
10 cm x 1.2 m (4 inches x 4 feet) to 15 cm x 1.2 m (5.9 inches x 5.9 feet):						
Blackeye sale	39.99	9.06	9.73	58.78	91.28	51.29
Joule sale	24.53	6.93	12.93	44.39	76.89	52.36
Weighted average	$32.26	$8.00	$11.33	$51.59	$84.09	$51.83
Weighted average (per over-dry tonne)	$35.57	$8.82	$12.49	$56.88	$92.71	$57.14

---

*1 Large end diameter in centimetres (inches), length in metres (feet).

*2 Includes 50 km additional hauling at $0.36 per oven-dry tonne per kilometer on paved roads = $18.00 and chipping at $17.65 per oven-dry tonne.

*3 Assumes yarding costs borne by Forest Service as a land management measure.

*4 Costs have been converted to March 1984 Canadian dollars using a 7 1/2 percent inflation factor and $1 U.S. = $1.24 Canadian.

debris.[23,24,25] These studies have been centred around the southwest Vancouver Island region and thus would be directly applicable to Bamfield and possibly to Bella Bella. It was noted that the majority of the recoverable logging residues were found at the landings or within 30 m of the roads in areas of highlead cable logging.

The cost of conventional recovery of logging residue at landings and along logging roads was determined for a typical logging show after the logging was completed. This cost was compared with alternative residue collection systems as shown in Table AA7-4. Under this scheme a choker equipped skidder would pile the larger wood waste at roadside for pick-up by self-loading logging trucks. Production per truck varied with terrain, piece size, total volume available and transportation distance, but an average collection of 79.8 m^3/day could be expected.[23] The production was based on an 8-hour working shift and a 32 km (one-way) hauling distance which resulted in an actual cost of \$15.51/m^3 (March 1983 dollars). This method is assumed to apply for providing wood fuel for Bamfield.

To reduce collection costs for the logging residues, alternative transport methods could be used in conjunction with an active logging operation. These methods utilize spare loader operating time at the landings to load residue onto four bunk residue trailers, or into demolition trailers or containers. Each method has specific advantages and disadvantages depending on the particular landing site. From the FERIC study the costs of delivered logging residue by alternative recovery systems ranged from \$9.19/m^3 to \$9.62/m^3. (March 1983 dollars).[23] The container system was the most promising and with design and size changes could possibly achieve residue recovery costs in the order of \$5.30/m^3 (March 1983 dollars).

The species distribution of the recovered wood waste was: 46 percent cedar, 29 percent hemlock, 22 percent fir and 3 percent balsam. Approximately 60 m^3/8-hr day could be recovered at each landing during active logging without disrupting the actual logging operation. The study was based on logging to a close utilization standard (logging down to a 15 cm diameter top and 3 m long). Logging residue was recovered to a 10 cm diameter and 2.4 m long. Larger diameter short ends were also recovered.

During discussions with MacMillan Bloedel it was indicated that, of the 10 or so landings in the Bamfield

TABLE AA7-4

LOGGING RESIDUE COLLECTION PRODUCTIVITIES AND COSTS (1983 Canadian Dollars)

	Conventional		New Systems	
	Self-Loading Truck	Four-Bunk Trailer	Demolition Trailer	Containers
Number of test days	9	9	2	8
Number of loads	36	26	7	39
% Delay time	2	26	24	20
Size of load (m^3)	20.3	21.8	15.9	10.9
Volume recovered (m^3)	730.07	565.77	111.07	425.01
Piece size (m^3/piece)	0.43	0.68	0.69	0.34
Time per load (hours)	2.04	2.61	2.03	1.52
Production/8-hour shift (m^3)	79.8	66.6	61.7	57.2
Cost/m^3 recovered	\$15.51	\$9.19	\$9.24	\$9.62
Cost/ODtonne*[1] (March 1984$)	\$35.35	\$20.94	\$21.06	\$21.92

*[1] Conversion factor is 2.12 m^3/ODtonne; inflation factor is 7.5 percent.

area, 2 or 3 could be used at one time in order to provide container loading of wood waste with a minimum of disruption to the logging operation. Some transfer of costs from the logging operation to the residue collection would be negotiated and would add marginally to the cost of the wood fuel, [Al Dent, MacMillan Bloedel, personal communication].

(ii) Tree Farms

A. Introduction

A tree farm involves managing a tract of forest on a sustained yield basis in order to provide a reliable source of fuel for electrical power generation. To date the harvest of hardwoods, such as white birch, trembling aspen, black cottonwood, red alder, and big leaf maple, in British Columbia is only about 16 percent of the Annual Allowable Cut, and thus these trees are a potential source of wood fuel.

Some hardwoods are processed for secondary wood manufacturing and a limited amount of hardwood chips is used in pulp and paper production. The hardwood stands are expected to be a depletable resource because the areas that have been cleared would most likely be re-seeded with commercial softwood trees. However, under suitable circumstances wood fuel could be obtained from an area dedicated as a tree farm for fast-growing, short-rotation trees.

Red alder (Alnus rubra) is a fast-growing indigenous tree found in the lower river bottom areas around Bamfield and may be a viable wood source over the long-term. Although soil conditions, topography and climate in the Bella Bella area are much less suitable for the cultivation of trees, a tree farm would provide the most reliable wood fuel source for a thermal generating station at that location. More site specific analysis of this source of wood fuel is covered in Part A Section 5.7 and Part B Section 5.7.

B. Tree Farm Fuel Costs

Studies based on the cultivation of red alder have indicated that a medium quality site could produce an average wood fuel yield of 106 m^3/ha (1520 ft^3 or 19 ODtons/acre) after a 10-year growing period.[23] Data shown on Table AA7-5 confirms that maximum stem and branch productivity is between 8 and 16 years. With fertilization, irrigation and weed control, higher

TABLE AA7-5

YIELD PER HECTARE, TREES PER HECTARE AND AVERAGE TREE SIZES FOR MEDIUM SITE ALDER STANDS*1

Age of Stand Years	Yield Per m^3/ha*2	Mean Annual Increment m^3/ha	Number of Trees per ha	Average Volume Per Tree m^3
10	106	10.6	3955	0.027
20	199	9.9	1385	0.144
30	276	9.2	755	0.367
40	327	8.2	505	0.646
50	364	7.3	395	0.920
60	392	6.5	345	1.133

---

*1 From "Normal Yield Tables for Red Alder" (B.C. Forest Service, 1938).

*2 Trees 1-inch d.b.h. and larger; recalculated from Imperial units.

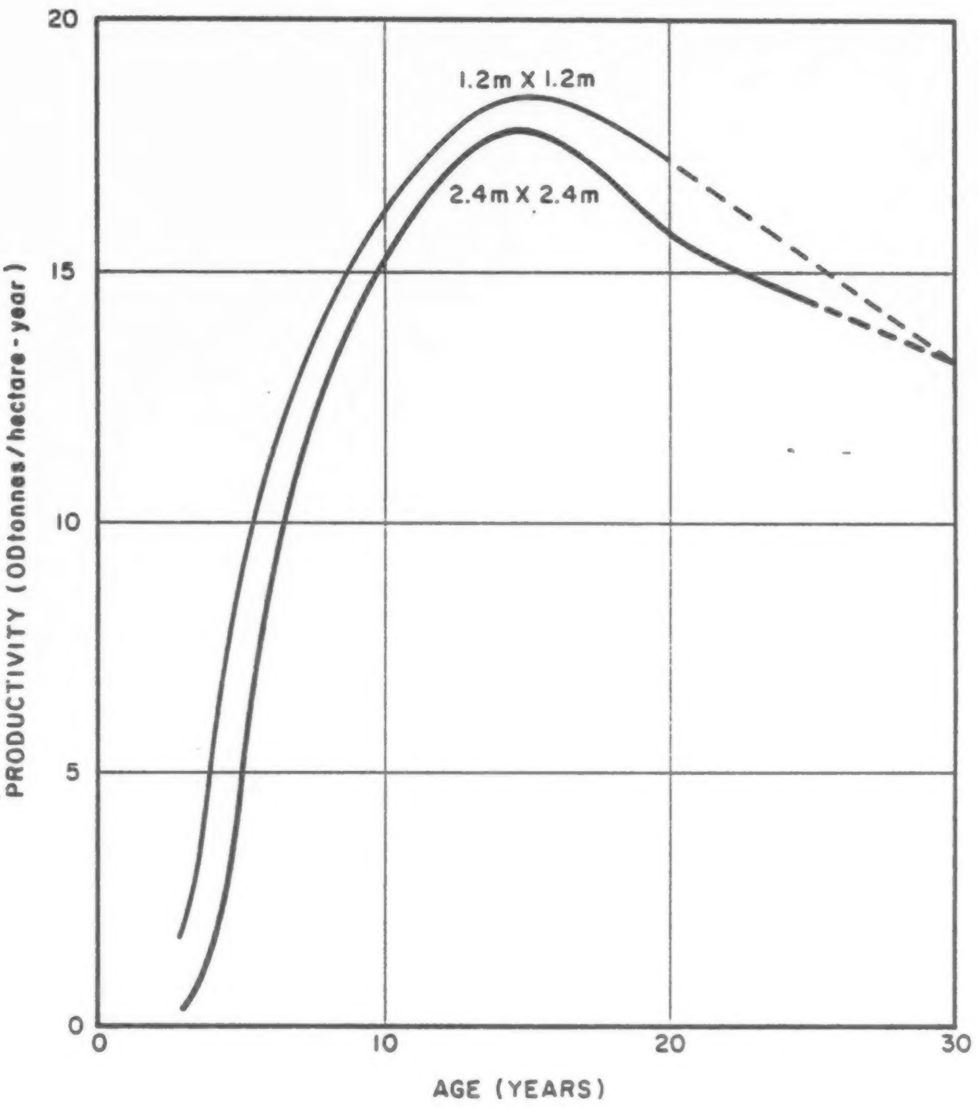
productivity is possible. The maximum wood production rate is for a 10 to 15-year growing period as illustrated for hybrid poplar in Fig. AA7-1.[26,27]

For this study it is assumed that an annual sustained productivity of 4.24 ODtonnes/ha (1.9 ODtons/acre) could be obtained from a managed plantation. It would require 2800 ha to fuel a 2600 kW wood-fired gasifier-engine generating station operating at a 45 percent load factor (10.35 GW·h/a electricity production) for Bella Bella. Similarly, a 1300 ha tree farm would be required to fuel a 1.0 MW wood-fired gasifier/engine generating station operating at a 53 percent load factor (4.65 GW·h/a electrical production) for Bamfield. It has been assumed that the oven-dried wood fuel has a heating value of 16.74 MJ/kg (7200 Btu/lb) and that the generating station heat rate would be 19 250 kJ/kW·h (corrected for 10 percent station services). In both cases considerably less wood fuel and consequently a smaller tree farm would be required for a conventional wood-fired boiler/turbine generating station with an assumed heat rate of 16 440 kJ/kW·h.

The cost of wood fuel harvested from an energy plantation is based on an estimate derived in late 1978.[15] This estimate includes capital, operating and the servicing cost of equipment, depreciation, administration, supervision and labour. These costs have been inflated to March 1984 Canadian dollars and are listed in Table AA7-1 where they are compared with recovery logging residues.

Tree farm or forest residue road hauling costs were estimated (in March 1984 Canadian dollars) to range between $10.04 and $21.20 for a one-way haul distance of 16 km to 65 km respectively.[15] The trip time was calculated on the following basis: loading time 20 minutes, unloading time 10 minutes, 8 km (one-way) on a logging road of an average speed of 24 km/h, an additional distance on a main haul road at 60 km/h and time available per day 9.0 hours (i.e., delay time per day 5 hours). The estimate is also based on a truck loading of 14.2 m^3 (5 cunits) for the first 16 km and 28.4 m^3 (10 cunits) for any additional miles; i.e., trucks with a residue box would operate from the landing to an assembly area and trucks with trailers would operate from the assembly area to the thermal plant. Incremental haulage costs are assumed to be approximately $0.36/tonne/km.[20]

Barge hauling and associated costs have been estimated as follows:[15]



REF: EK AND DAWSON, 1976

B.C. HYDRO

FIGURE AA 7-1

PROJECTED PRODUCTIVITY LEVELS FOR FIRST CROP HYBRID POPLAR, *Populus tristis*

1. Off-highway truck haul to tidewater:

One-way haul distance:	8 km	$ 7.50/ODtonne	
	16 km	$12.50/ODtonne	
		Average	$10.03/ODtonne

2. Fuel processing:

Annual wood fuel production	30 225 ODtonne	
Annualized capital costs	$170 900	
Annual operating costs	128 200	
Total costs	$299 100	
Cost per oven-dry tonne		$ 9.90/ODtonne

3. Barging costs:

One-way barging distance up to 240 km	$ 7.25/ODtonne
Total cost to a Tidewater Thermal Generating Station	$27.18/ODtonne

Notes

a. Barge costs assume maximum barge and tug utilization. For a smaller wood waste-barging operation the daily costs (note d) have been applied to the annual volume of wood waste hauled.

b. Off-highway truck hauls assume 200 shifts per year with three trips per day based on a loading time of 20 minutes, average speed of 24 km/h (15 mph) and 10 minutes to unload; truck loading is assumed to be 28.4 m^3 (10 cunits).

c. Assembly yard costs are speculative. The equipment required includes a hog mill, grapple yarder, conveyors from the hog mill to storage, and a wharf and barge loading system. Operating costs include equipment operating costs and labour.

d. The barge costs are based on discussions with a tug and barge operator. Assumptions are: barges would be new equipment at a cost of $798/barge-day. Loading would be 2840 m^3 (1000 cunits) per barge; yarding costs were estimated at 6 hours at $171/hour. Line haul tug costs were based on a tandem tow, $6490 per day for the tug and an average speed of 13.4 km/h including a bad weather allowance.

(iii) Municipal Solid Waste (MSW)

Studies done in North America indicate that the total annual weight of garbage collected in a community would provide fuel for less than 2 percent of its annual electric power requirements.[28]

The present situation in Bella Bella/Shearwater is that MSW is burned in open fires at the respective landfill areas on Campbell Island and Denny Island. A small landfill serves Bamfield and the villages at Pachena Bay and Anacla, the Sarita River landsort, the logging camp at Franklin River and the Poett Nook recreation area. At both sites MSW disposal is not a community problem and incineration with energy recovery would be an expensive and unnecessary option. It can be concluded that the use of MSW as a fuel for generating electric power is neither economic nor practical for Bella Bella or Bamfield.

(iv) Peat

A. Introduction

Peat is dead and partly decayed plant material, which has accumulated in a wet environment, where stagnant waters inhibit the circulation of oxygen vital to decomposing organisms. Peat is widespread over the coastal lowlands of British Columbia where muskeg is a dominant feature of the landscape. The muskeg contains fibric and mesic peat derived from sedges and sphagnum moss.

Peat is classified using a humification scale established by Von Post;[29] the characteristics of each peat are described in Table AA7-6. Better fuel peats are above H5, but peat classified as low as H3 may be used in a thermal plant. Deeper peat is more decomposed and has a higher Von Post index number.

Several characteristics which are important in determining the potential of peat for utilization include density, mineral matter content, moisture content and thickness.[30] The in situ bulk density of peat is dependent on its degree of decomposition and its mineral matter content. The bulk density can range from 48 to 320 kg/m^3.[29] Fibric peat usually contains less than 2 percent mineral matter which results in a lower density. The density of peat increases with increasing decomposition. The water content, when saturated, is commonly about 95 percent. If the peat is less decomposed it drains more easily because there is less colloidal peat.[3] However, the more decomposed peats are

TABLE AA7-6

SWEDISH GEOLOGICAL SURVEY
METHOD FOR DETERMINATION OF HUMIFICATION OF RAW PEAT SAMPLES
(FROM VON POST 1926)

				Upon Squeezing Through Fingers		
Humification Scale	Evidence of Degree of Decomposition	Plant Structure	Mud Present	Water Passing	Amount of Peat Substance Passing	Residue
1	Nil	-	Nil	Yes Clear and colourless	-	-
2	Almost nil	-	Nil	Yes Clear but yellow brown	-	-
3	Very little	-	Little	Yes Distinctly turbid, very turbid	-	Not pulpy
4	Little	-	Some	Very turbid	-	Somewhat pulpy
5	Fairly evident	Barely recognizable	Moderate	Moderate amount	Some	Very pulpy
6	Fairly evident	Indistinct less in residue	-	-	One-third	Very pulpy, shows plant structure more than unsqueezed turf
7	Strong	Fairly recognizable	Much	Yes Gruelly and dark in colour	One-half	-
8	Strong	Very indistinct	Much	Yes or no If it does, gruelly	Two-thirds	Consists of more resistant roots, fibres, etc. in main
9	Almost fully decomposed	Almost unrecognizable	Very much	-	Almost all, as a uniform paste	-
10	Completely decomposed	Entirely without plant structure	Entirely muddy	No free water	All	-

better fuels. Unfortunately, potential fuel peat underlies horticultural peat which must be harvested first. Therefore, a market for the horticultural peat is necessary in order to effectively excavate the fuel peat. A density-moisture curve was derived by Montreal Engineering in a report prepared for Energy, Mines and Resources Canada (Fig. AA7-2).[29] Similarly, a heating value-moisture curve was derived in the same report (Fig. AA7-3).[29] Most peats are acidic and have a pH ranging from 3 to 6. A peat should be more than 1.8 m thick for satisfactory harvesting.

The advantages of peat are its widespread occurrence, its relatively easy accessibility, low land use values, and low sulphur content.

B. Production

Peat is harvested by both dry and wet methods.[31] For dry harvesting methods the peat is extracted by first constructing ditches to drain it. Trees and stumps may be removed and levelling begun after 1 to 3 years of draining. Development work is completed after about 5 years.[29] The dry harvesting methods produce sod peat or milled peat with a moisture content between 35 and 50 percent.[31]

Sod peat harvesting is the oldest method of excavating peat and it is still practised in the U.S.S.R., Ireland and Finland.[31] In this method a machine scoops, macerates, extrudes and spreads the peat which is then ready for drying.

Milled peat harvesting involves cutting a layer 125 mm thick. The shreds of peat are allowed to dry in the field where they are turned over every 2 to 5 days to promote the drying; if it rains the process is repeated. Milled peat harvesting is the most common method of peat excavation and it is practiced extensively in the U.S.S.R., Ireland and Finland and to some extent in the United States. The basic methods of milled peat production are Peco, Hacu and pneumatic harvesting.[29] The Peco and Hacu methods differ principally in their treatment of stockpiles of peat. In the pneumatic system a thin layer of peat is sucked into a carrier and a new layer is milled by a milling unit that is towed behind. Storage is similar to the Haku system.[29] The pneumatic system is favored in most Canadian operations. The Haku system increases security of supply with off-the-bog storage and it allows for blending at the central pile,

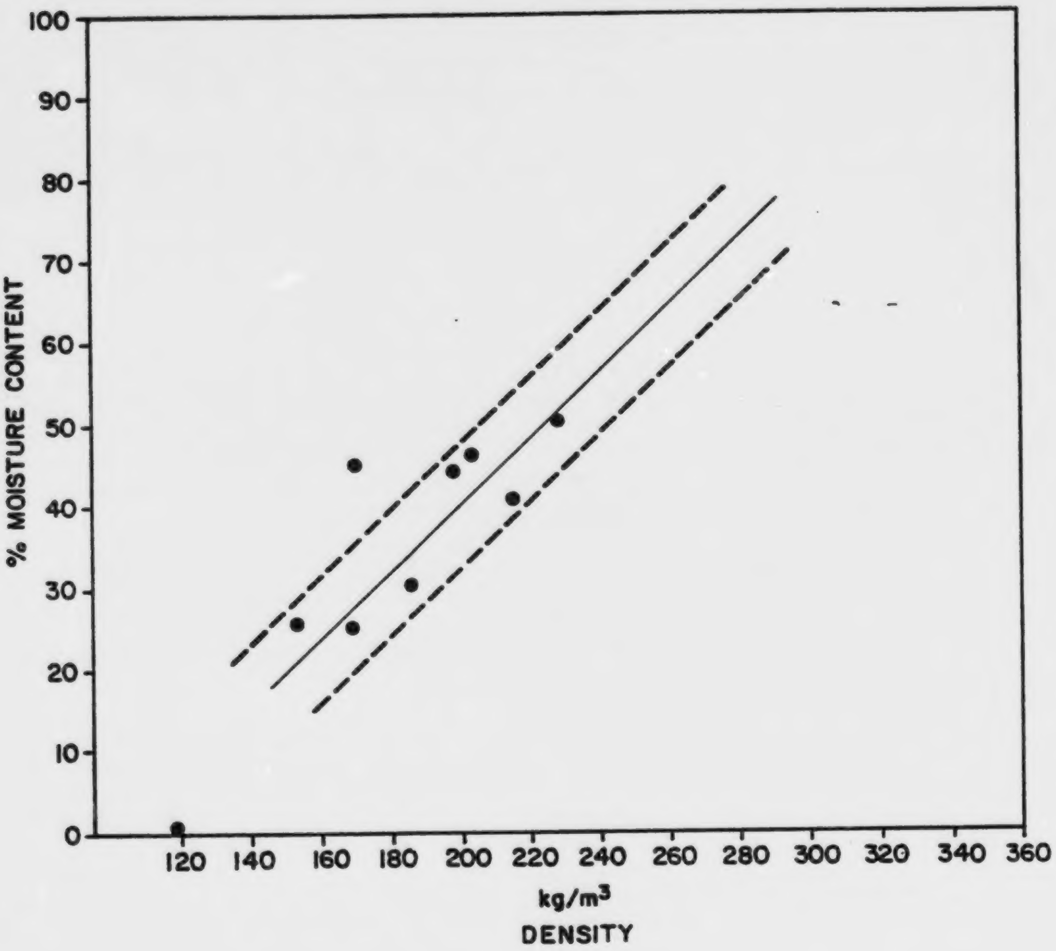


FIGURE AA7-2

DENSITY/MOISTURE CONTENT OF FUEL PEAT

NOTE: THE POINTS REPRESENT THE CHARACTERISTICS OF A NUMBER OF CANADIAN PEATS

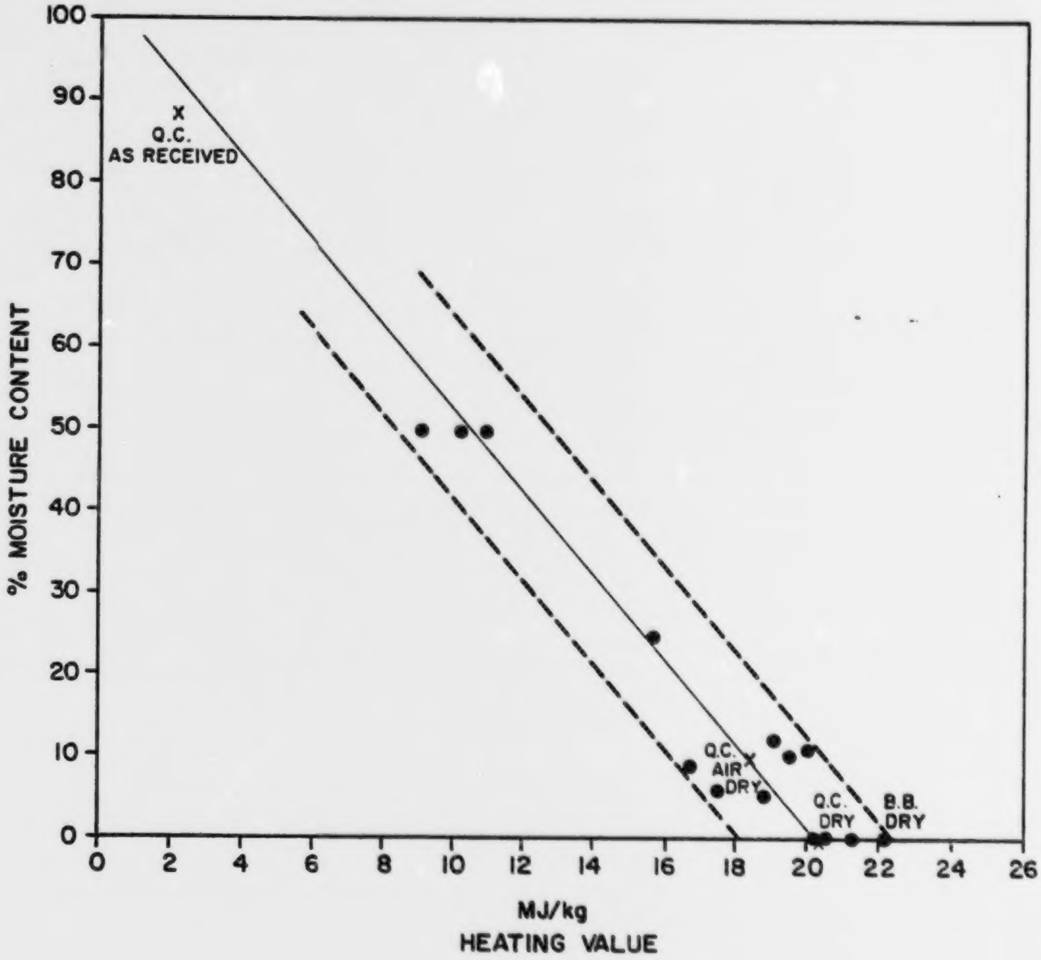


FIGURE AA 7-3

HEATING VALUE/MOISTURE CONTENT OF FUEL PEAT

NOTE: THE POINTS REPRESENT THE CHARACTERISTICS
OF A NUMBER OF CANADIAN PEATS

but the disadvantage over the Peco system is the high capital cost.

In wet harvesting methods, peat is harvested by using vacuum dredges, water monitors, clamshells or bucket excavators.[32] These methods produce peat with 80 to 97 percent moisture; the moisture content depends on the amount of pre-drainage. In wet harvesting the peat is transported from the bog by conveyor or as a slurry (less than 5 percent solids). The advantage of wet methods, particularly those methods where drainage is not required, is the small inventory of peat which the producer must have on hand.

There are a number of environmental considerations which apply to peat harvesting.[29] Drainage of water from peat bogs into estuaries and other salt water regions is expected to reduce the salinity near the discharge. This could adversely affect some marine life, but it could be expected to promote other marine life adapted to brackish conditions.

Harvested peat land could be tilled and lime added to reduce acidity, thus converting it to productive farmland as has been done in parts of Europe. In Sweden "mined out" peat bogs are being partly flooded to create lakes for recreation and some areas are being planted with fast-growing trees for future tree farming to provide fuel for thermal plants.[33] This method results in improved wildlife habitat for most species, although it is detrimental to some inhabitants of these bogs.

C. Transportation

In Ireland, where the Peco system is preferred, the transportation of milled peat is conducted by narrow gauge railway from the stockpiles to the power or briquetting plants.[29] The trains are loaded by a spiral feeder onto a jib belt conveyor. Cars are dumped by a rotary tipple at the plant, which is typically 6.4 km to 8.0 km from the peat bog.

In Finland, where the Haku system is preferred, the transportation to the plants is by regular truck (90 m^3 box) on existing highways. Roads to the storage sites are paved. Haulage distances are as much as 100 km.

In Vancouver, British Columbia the peat is excavated by a clamshell mounted on a hover-barge.[32] Water jets separate tree roots from the peat and the latter is slurried 4.5 km to the plant.

D. Dewatering

In dry harvesting operations the peat is dewatered effectively by solar methods; however, wet harvesting requires other methods such as a mechanical, biological, chemical and/or thermal methods.[31,34]

Mechanical dewatering of the peat slurry uses a combination of centrifuges, screens, vacuum filters, filter presses, screw presses or more commonly roll or belt presses. Roll or belt presses only reduce moisture content to 70 percent, but they have a large capacity. Chemical pretreatment can be used to improve mechanical dewatering and decrease moisture content to as little as 35 percent.

Chemical dewatering uses solvents which can solubilize large quantities of water at high temperature, and the liquids can be separated again when the temperature is lowered. The solvent is then recovered and used to remove more water.

Biological dewatering relies on anaerobic bacteria which break the cellular structure of the peat and permit it to be more effectively mechanically dewatered. Studies of this method are at a very preliminary stage.

The partly dewatered peat can be dried to 30 or 35 percent by thermal drying which utilizes rotary drum, fluidized bed or flash dryers.[34] Fluidized bed and flash dryers are more suitable than rotary drum dryers because of their potential for more capacity. Flash drying using waste heat is the most common method of drying for powerplant applications.

Electro-osmotic dehydration has been tried in Germany, but the method only reached levels of 70 percent moisture.[34] In general, electrical methods are not economical.

E. Utilization

Direct Firing

The peat deposits in Canada represent a significant energy source, but there is no significant peat-fired steam generation in the country. However, the technology is well developed in Europe, primarily in Russia, Ireland and Finland where it is used as a fuel for the generation of electricity.

The moisture content of peat is one of the most important properties affecting the utilization of peat in thermal powerplants. When air dried to 50 percent moisture, typical peats have a heating value of 9300 to 11 600 kJ/kg. The sulphur content of peat is very low and the ash content varies considerably, from 2 to 70 percent of the dry peat depending on the way water was supplied to the peat bog. If the water comes mainly from precipitation the ash content is low. If the bog is periodically flooded by surface water, sediments will significantly increase the ash content of the peat.

Handling of peat poses some special problems. If the moisture content falls below 40 percent there is the danger of spontaneous combustion, of explosive dust mixtures and the nuisance of dust affecting people. If the moisture content is above 55 percent the peat bridges in storage bins and chutes, and freezes when the ambient temperature is low.

The properties of peat, such as particle size, moisture and ash content, have a significant effect on boiler design. Furnace size is primarily determined by two factors:

1. Sufficient residence time is required to ensure complete combustion.

2. Sufficient radiant heat absorbing surfaces are required to minimize slagging and fouling.

In general, furnace sizes for peat are much larger than for comparable coal-fired units. Air heaters require careful design to avoid plugging and to provide the high combustion air temperature necessary for stable combustion with the high moisture fuel.

Particulate removal from the flue gas must be effective. In general, the sulphur content of peat is so low that SO_2 emissions are not a problem. While fuel nitrogen is similar to many coals, peat has high volatiles and is amenable to low NO_x-firing techniques. The high moisture content of peat tends to limit flame temperature in the furnace to a level where thermal NO_x formation is not significant.

While the use of peat as a fuel presents many design and operating problems it may well be considered as an alternative if coal is not readily available.

Indirect Firing-Gasification and Liquefaction

New methods of peat utilization are being examined in the U.S.S.R., Finland, Sweden, United States, Canada and Israel. Many of the processes could be operated to favor either gases or liquids, the latter under less severe operating restrictions. Based on hydrocarbon gas yield, peat is appreciably more reactive than lignite in the gasification process.[29] The reactivity is probably related to the higher volatile matter in addition to other unknown factors.

In Canada, Quebec Hydro has concluded that a 0.75 MW generating station fired on gasified peat is feasible; a gasification plant is proposed for Anticosti Island using "pyrolysis" in limited air.[33] The University of Sherbrooke and Beak Consultants have demonstrated the technical feasibility of producing bitumen from peat using heat and catalysts in a reactor vessel. The bitumen could be used in oil-fired burners with little upgrading. In the future, peat gasification may provide fuel for a thermal plant where more economical alternatives are unavailable.

(c) Coal

There are two major systems for coal classification.[35] The American system has been used in this report and under that system coals are classified according to fixed carbon or volatile matter content on a dry, mineral-matter-free basis for higher rank coals and according to heating value on a moist [in equilibrium with air at a relative humidity of 97 percent and a temperature of 30°C] mineral-matter-free basis for lower rank coals (Table AA7-7). The other system is the International system which is included only for reference.

There are no known sources of coal near Bamfield or Bella Bella and the geology is unfavorable for the occurrence of coal near Bella Bella. Therefore, coal would have to be brought from elsewhere. For purposes of this study, it is assumed that coal for Bella Bella would consist of high volatile A to B bituminous coal from Telkwa. Similarly, for this study it is assumed that coal originating in the Crowsnest Coalfield near Sparwood would be brought to Bamfield from Roberts Bank.

Combustion technology is described briefly at the introduction to Section A.7(c). More detailed descriptions of the plant and plant requirements are described in Section 5.7(e) in Parts A and B for the specific plants at Bamfield and Bella Bella.

TABLE AA7-7

CLASSIFICATION SYSTEMS OF COALS

International System				American System		
Class No.	Volatile Matter[*1] (%)	Heating Value[*2] (Btu/lb)	Total Moisture[*3] (%)	Group	Volatile Matter[*4] (%)	Heating Value[*5] (Btu/lb)
0	0-3	-		Meta-anthracite	≤2	
1A	>3-6.5	-		Anthracite	>2-8	
1B	>6.5-10	-				
2	>10-14	-		Semi-anthracite	>8-14	
3	>14-20	-		Bituminous lv	>14-22	
4	>20-28	-		Bituminous mv	>22-31	
5	>28-33	-				
6	>33	>13 950		Bituminous hv A	>31	≥14 000
7	>33	>12 960-13 950		Bituminous hv B	>31	13 000-14 000
8	>33	>10 980-12 960		Bituminous hv C	>31	10 500-13 000
9	>33	>10 260-10 980		Subbituminous A	-	10 500-11 500
10	-	<10 260	<20	Subbituminous B	-	9 500-10 500
11	-	<10 260	>20-30	Subbituminous C	-	8 300- 9 500
12	-	<10 260	>30-40	Lignite A	-	6 300- 8 300
13	-	<10 260	>40-50	Lignite B	-	<6300
14	-	<10 260	>50-60			
15	-	<10 260	>60-70			

[*1] Dry, mineral-matter-free basis.

[*2] Gross, moist, mineral-matter-free basis (equilibrated at 30°C and 97 percent relative humidity).

[*3] Ash-free basis.

[*4] Dry, mineral-matter-free basis.

[*5] Moist, mineral-matter-free basis (equilibrated at 30°C and 97 percent relative humidity).

[*6] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class.

(d) Thermal Technologies

(i) Introduction

A thermal electric powerplant can be generally defined as one in which the energy of a burning fuel is used to drive an electric generator either directly or indirectly. The prime mover could be an internal combustion engine (diesel or gasoline), a gas turbine, a steam engine or a steam turbine. This study considers the use of conventional wood-fired and coal-fired boiler/steam turbine generating units as well as biomass gasification combined with either an internal combustion engine generating unit or a gas turbine generating unit.

A. Conventional Thermal

Fuels which could be burned in a boiler to produce steam cover a wide range, from the conventional fuels such as coal, wood, oil and natural gas to exotic wastes such as corn cobs, walnut shells and bagasse. Coal and wood, the latter in the form of hog fuel, are the fuels which were considered in examining alternatives for a Bella Bella or Bamfield thermal generating plant.

A typical, small thermal generating plant would have a steam boiler, fired by the selected fuel, producing superheated steam to drive a turbine which in turn would drive the electric generator. Associated with this equipment would be the fuel storage and ash disposal areas, the fuel and ash handling equipment, a supply of water to provide boiler make-up and condenser cooling, pollution control devices, the electrical switchyard, and the necessary operating, maintenance and administration services.

The selection of an appropriate site for a plant is dependent on a number of factors, with public acceptance being of primary importance. Powerplants are often thought of as dirty, ugly and noisy facilities. This concern can be minimized through good engineering and architectural design. Control of coal and ash dust from the storage and disposal areas is necessary. Stack emissions must be kept within established limits by such means as cyclone separators and bag house filters. Noise pollution can be minimized by the use of sound-proofing materials and vent silencers.

Another factor affecting site selection is the supply of water for boiler feed and condenser cooling. The use of cooling towers reduces the amount of cooling water required, but they would be expensive and could cause local fogging conditions. Once-through cooling using ocean water, lake water or river water are other alternatives. For large plants there could be a danger of thermal pollution from cooling water discharge if a large quantity of water is involved.

The availability of a fresh water supply for boiler feed could present a problem at some sites and would require a detailed investigation of the present domestic water supply.

There are other factors to be considered in site selection such as availability of municipal services, the supply of labour, convenient access, freedom from danger of flood and earthquake, area climate, and room for future growth.

One final consideration are the facilities for fuel delivery to the site. It has been assumed that all fuel, both coal and wood waste, would be delivered by barge or truck because of the remote locations. Therefore, it is necessary to have a location on tide water where barge landing facilities could be constructed.

B. Gasification

A second method of thermal electric power generation from wood fuel involves wood gasification and subsequent use of the gas in a steam boiler, gas turbine or diesel engine. Gasification of biomass, including processed wood waste, peat or even municipal solid waste, has been demonstrated to operate satisfactorily to produce a low Btu fuel gas.

Gasification is the decomposition of long-chain molecules (which give wood its structure) into products which are flammable. A pyrolysis reaction occurs when heat is applied to wood or other biomass fibre. Initially all moisture is driven away. As the temperature of the fuel rises products of gasification (predominantly carbon monoxide, hydrogen and hydrocarbons such as methane and ethylene) are given off. The exact nature and composition of the gases emitted is dependent on the rate and intensity of the heat being applied to the fuel.

In a gasifier, the object is to combine the fuel with as little oxygen as possible, maintaining just sufficient heat to sustain the pyrolysis reaction. Residual carbon is combined with more oxygen (air) and steam to create more gasification product. The combined gasification products constitute a low Btu gas (100 to 300 Btu/scf) which could be burned in a boiler, a reciprocating engine, or gas turbine to generate power.[36] A medium Btu gas could be generated if oxygen were used instead of air in the gasification process. The gas produced leaves the gas cleaning equipment at near atmospheric pressure and at 700° to 800°C (1300° to 1500°F).

Several gasifiers are commercially available and are being used successfully to generate process heat, particularly for lumber kilns, lime kilns and low pressure steam boilers. Several diesel and gas turbine engine manufacturers have modified engines to burn the low-Btu gas produced by gasifiers. However, problems still exist in combining the wood gasification technology with the engine generation of electric power. Clean-up of the gas and disposal of the oils and tars produced in cooling the gas are the major problems. Reliability and continuity of operation, without full time supervision, is uncertain because of plugging of the automated fuel feed and ash removal systems. These problems could be solved if there is a real market for the technology.

Imbert Energietechnick (West Germany) and Duvant-Renault (France) are pioneers in wood gasification technology and have installed gasifier engine generator units, worldwide.[36,37,38] Their installations are in the 120 kW to 800 kW size range. Imbert gasifier engine generator units have been installed in Canada. A 60 kW unit was installed at Hudson Bay, Saskatchewan and a 120 kW unit was installed at Fort Providence, NWT;[39] only the 120 kW unit is available for operation. Both gasifiers were connected to modified Duetz diesel generating sets. The Fort Providence unit is presently operated on a standby basis because it requires continuous supervision which is costly for a small unit, but the unit can be started up and operated within 15 minutes.

One of the more developed gasifier-engine generator systems in the United States is the Biomass-Caterpillar generating unit (California) designed for installation at Petersburg, Alaska.[40] The unit was tested in Anchorage Alaska, but suitable arrangements could not be made with the sawmill operator for supplying the fuel, consequently the system was never operated. Numerous biomass gasifiers have been designed and tested in the United States in heating applications, but it is believed that no gasifier has been used successfully to fuel an engine generator set for the production of electricity.

Omnifuel Gasification (Ontario, Canada) manufactures a successful fluidized bed gasifier.[41] The basic 60 million Btu gasifier is capable of supplying low Btu gas to fuel a 6000 kW diesel generating unit; however, it has not been demonstrated at this time and would be too big for Bamfield or Bella Bella.

A Heuristic (B.C., Canada) 3 million Btu/h two-stage gasifier has been specifically designed to produce low tar gas for use in an engine generator set, but it has not been tested to date.

A 350 kW three-chamber cross-draft wood gasifier is being built by Peter-Sun as a demonstration project at Ramsey, Ontario, but again the system has not been operated.

Lamb-Cargate and General Electric have recently designed a gasifier and gas turbine generating system.[42] The system consists of two 106 GJ/h Wet Cell Burners which feed a 10 MW, Frame 3 GE gas turbine generating unit. The station would consume 16 ODtonnes of waste wood per hour at peak load. The gasifier itself has been used in demonstration plants for direct-fired kiln drying and to produce steam, but it has not been used in conjunction with an electrical generating plant and would be too large for consideration in this study.

Steam Turbine Generation

The fuel gas from gasifiers could be burned in conventional gas-fired boilers. The use of the fuel gas requires special burners to handle the hot gases, and the increased mass flow rate in the boiler would cause some derating (to about 70 percent of the nameplate steaming rate). While the steam boiler/steam turbine technology is well developed, it is not particularly well suited for small applications (1 MW or less) for the following reasons:

1. A licensed boiler operator would be required.

2. Cooling water would be required for the condenser (if used).

3. Conversion efficiency to electricity would be relatively poor.

4. Capital costs per unit of power produced tend to be high.

5. The overall system tends to be overly large relative to systems for other solid fuels.

Reciprocating Engine Generation

Both spark ignition and dual fuel compression ignition engines have been operated on low Btu gas from biomass gasifiers. The engines place considerable constraints on the fuel gas quality. The gas must be cooled to nearly ambient temperature. This results in the loss of the sensible heat in the gas, typically 10 to 15 percent of the total energy value of the gas as it exits the gasifier. Further, the gas must be carefully cleaned to remove virtually all of the particulates and tars to prevent abnormal wear and fouling of the engine's moving parts. Thus, even before the gas has been fed to the engine, considerable energy has been lost.

Considerable money must be invested in gas cleaning equipment which tends to be troublesome, and which produces undesirable waste streams. Once the gas has been cleaned, it is fed to the engine where its low heating value typically causes reductions in performance (to about 50 to 60 percent of the engine nameplate rating). Some of these losses could be overcome with turbocharging, but there are upper limits even here because of potential auto-ignition problems associated with compressing the gas-air mixture.

In spite of these problems numerous systems are being tested because reciprocating engines offer the only potentially economical and available powerplants suitable for small installations.

Gas Turbine Generation

Gas turbines offer the opportunity of using low Btu fuel gas at the temperatures and pressures where they are most easily produced. Gas turbines also offer high potential conversion efficiencies.[43] The conventional open cycle gas turbine configuration offers simplicity, reliability, long lifetime, and compact size. In the open cycle gas turbine, air is compressed and then directed to a burner where fuel is added and burned. The temperature of the gas stream is raised and then the gas stream is expanded over the turbine. The turbine provides power to drive the compressor and the electrical generator. Most of the fuel energy is lost as compressor power and as thermal energy in the exhaust stream. Some of the exhaust energy could be recovered with the installation of waste heat boilers. However, the simple open cycle gas turbine would continue to suffer from the following problems when trying to utilize low-Btu gas from a biomass gasifier:

1. Cycle efficiency is low.
2. Gases must be cleaned and cooled before gas compression.
3. Gas compression involves substantial parasitic losses.
4. The large gas flow through the turbine imbalances the compressor/turbine match with losses of performance or requirements for major internal engine modifications.

Some of the disadvantages of the simple turbine could be overcome in the recuperated gas turbine configuration. In this arrangement the compressor discharge is directed to a heat exchanger (termed a recuperator or regenerator) which preheats the compressor air using the turbine exhaust. The preheated air is directed to the burner where fuel is added and the temperature is raised to the final turbine inlet temperature. The recuperator could thus offer a considerable increase in cycle efficiency. However, gas cooling and cleaning equipment would be required with the associated losses of the gas sensible heat, and parasitic compressor losses still exist. For typical components that could be used, the parasitic compressor losses could amount to as much as 30 percent of the engine net power output. Further, the problem of imbalanced flow between the compressor and the turbine still exists.

More of the disadvantages of the gas turbine as the prime mover are overcome by using the downheated or exhaust-fired cycle. In this arrangement the compressor discharge air is heated in the recuperator until it reaches the desired turbine inlet temperature. The hot air is expanded over the turbine to produce shaft horsepower. The turbine exhaust in this case is just hot air, and is used as preheated combustion air for the burner. The burner raises the stream temperature and the gases are then passed over the other side of the heat exchanger. Using this configuration, the lifetime of the turbine hot section is estimated to be 50 000 to 100 000 hours because of the absence of contaminants and corrosive substances in the hot gas stream. Thus the reliability of the gas turbine itself is expected to be exceptionally good.

The downheated cycle gas turbine offers the following benefits when filled with low Btu gas:[43]

1. The overall efficiency is expected to be 21 to 25 percent.

2. Low-Btu gas may be used directly from the gasifier enabling the use of the sensible heat in the gas as well as burning the condensible oils and tars contained in the gas.

3. No products of combustion pass through the gas turbine, thus eliminating many potential turbine problems.

There are, however, potential design and operating problems associated with the heat exchanger because of the high operating temperature and the fouling caused by the ash in the combustion gases. At this time the high cost of the heat exchanger is a major drawback to wide-scale application of the downheated turbine cycle. Some engine generator control problems are also expected. Still the generation of electricity from biomass in gasifiers and engine generators is a developing technology. As noted, gasification of biomass produces a low-Btu gas which could be burned in a thermal generation unit to produce electricity.

For this study the most commercially advanced gasifier engine generating system is believed to be the Imbert gasifier feeding a Duetz diesel electric generating set in the 100 to 400 kW size range.

A.8 GEOTHERMAL

(a) Introduction

Natural underground heat sources are created by volcanic activity in the earth's crust. These heat sources can give rise to geothermal reservoirs which usually contain hot water or steam. The hot water or steam can be tapped by drilling wells (similar to oil wells) to bring the geothermal fluid to the surface, where it can be used to generate electrical energy in a thermal powerplant. As is the case with petroleum resources, special geological conditions are required in order for geothermal reservoirs to exist. These conditions occur to some extent in B.C. and several areas appear to have significant geothermal potential. Most of the resource potential would likely be located in the vicinity of volcanic complexes in the Coast Mountains.

Geothermal electric energy has been developed in several countries (e.g. the U.S., Italy, New Zealand and Japan), but to date there has been no development in Canada. Most of the existing developments are large-scale installations for utility grid applications. For example, the Geysers development, north of San Francisco, comprises about 20 units with capacities ranging from 50 to 100 MW.[5,44]

To date, there has been limited development of small-scale geothermal generating plants of the size that would be required for isolated, off-grid communities in B.C. However, some small wellhead powerplant modules are now commercially available with unit capacities in the range of 1 to 10 MW. Such units would likely require one or two production wells and a reinjection well. Typical production well depths would be in the range 1500 m to 3000 m.[2]

(b) Generation Technology

There are three basic types of geothermal powerplant systems which are in use or under development. Each type is briefly reviewed below in the context of small-scale development.[5]

(i) Dry Steam Systems

Dry steam is the rarest type of geothermal resource, but it is also the most desirable type for power generation. The powerplant technology is relatively simple and well developed (e.g. similar to a conventional low pressure steam turbines). It appears that only large-scale (e.g. 50 MW) units are commercially available.

(ii) Flash Steam Systems

Flash steam systems are used to generate power from hot water resources having temperatures above 210°C. In these systems, the geothermal fluid is "flashed" in a vessel to produce a steam/water mixture. The steam is used to drive a turbine and the water is reinjected (in some cases it may be flashed a second time, then reinjected). Small-scale wellhead flash steam powerplants are commercially available.

(iii) Binary Systems

For hot water resources with temperatures between 150°C to 210°C, binary cycle systems appear to be the most attractive means for electrical generation. In such systems, heat is transferred from the geothermal fluid to a secondary loop containing a low boiling fluorocarbon (e.g. freon) or hydrocarbon (e.g. isobutane). Heat transferred to the secondary loop vaporizes the fluid, and the vapor drives a turbine-generator. Binary systems have higher thermodynamic efficiencies than flash systems and require about one-third less heat input to generate the same amount of electricity. The binary process is being tested at a number of small-scale plants in the U.S. A number of technical problems remain to be resolved, but commercial units could be available by the end of 1986.

Binary systems may also be used in the development of hot dry rock resources, but proven commercial systems for these resources are still many years away.

(c) Costs

Assuming that a suitable geothermal resource is available, geothermal electricity would likely be cost competitive with diesel generation.

There are two main cost components for geothermal energy (J. Stauder, B.C. Hydro, personal communication). The first component is the capital and operating costs for the powerplant. These costs will vary depending on the plant capacity, resource characteristics and generation technology. In general, it appears that the unit capital and operating cost for a small-scale powerplant in the 1 to 10 MW range should be about 20 to 40 mills/kW·h (1983$).

The second cost component is the geothermal steam. This includes all costs associated with exploration, drilling and delivery of steam to the powerplant. Assuming a suitable resource is discovered, experience in the U.S. indicates that steam costs would be about 40 to 50 mills/kW·h.

(d) Constraints to Development

The main difficulty with the general utilization of geothermal resources is that they only occur in certain areas where conditions of adequate heat flow, rock permeability and groundwater exist. Unfortunately, there appears to be no inexpensive way of assessing these factors in order to estimate the geothermal potential of a specific area.

The presence of geothermal resources can be predicted to some extent by geological factors, but the potential can only be determined precisely by the drilling of large bore exploration wells. These wells may typically cost $3 to $4 million each, depending on depth and rock conditions. The cost and risk of drilling such wells appear to represent major deterrents to small-scale geothermal development.

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APPENDIX B

ENVIRONMENTAL IMPACTS OF APPLICABLE ALTERNATIVE TECHNOLOGIES

B.1 INTRODUCTION

The purpose of this appendix is to describe the potential environmental impacts which could result from the development of applicable alternative energy technologies. The potential environmental impacts consist primarily of effects on fisheries and other marine life, land animals, forestry, mining and socio-economic considerations. The following alternative technologies have been considered: small hydroelectric, tidal, wind, thermal (wood waste, tree farm, coal) and transmission (or distribution).

B.2 GENERAL ENVIRONMENTAL CONSIDERATIONS

(a) Small Hydro

Small hydro facilities in B.C. typically range in size from a few kilowatts to an upper limit of 20 MW. In general small hydro involves a simple diversion structure where head is developed by diverting flows from a higher to a lower elevation across a steep gradient. A penstock delivers the diverted flow from the higher elevations to the powerhouse at the lower elevation. Small hydro facilities may either operate on the available run-of-the-river flow or alternately a small dam may be constructed to regulate flows within the storage basin.

The structures associated with a small hydro project include a screened water intake, a penstock/flume, powerhouse, transformer station, transmission line, access road and if required a dam or weir to regulate flow. Construction of these facilities would increase total suspended particulate loading on the stream for a period of time as activity occurs along the stream bank and at the intake and outlet points. Direct alienation of land would occur as a result of right-of-ways for access roads and transmission lines. Improved access to the area along these right-of-ways could increase hunting and fishing pressure in the local area.

Protection of the fisheries resource is a major environmental concern in the development of small hydro facilities. Many of the coastal streams in British Columbia are used for salmon spawning to the point where water falls prevent further upstream migration. The same falls which restrict salmon migration are often the feature which gives the site its hydro power potential.

During construction, disturbances of the stream bed must be minimized to reduce stream sedimentation. High sediment levels could affect adult and juvenile fish by clogging their gills and displacing their food supply. Deposition of silt could cause damage to the food supply and to the eggs of salmon by interfering with the circulation of water through the gravel and causing suffocation.

(b) Tidal

The most common development concept for tidal energy is a dam-like structure (barrage) containing turbine generators placed across the mouth of a large basin. The structure creates a small head across the turbine by restricting the flow of sea water to and from the basin.

The environmental factors which influence the feasibility of tidal development are very site specific. Generally, however, the major environmental constraints involve effects on navigation, fish migration and marine ecology in the basin.

In many small, remote communities along the B.C. coast the only practical way to travel is by small boat. Many of the communities are developed on basins which provide protected waters for moorage and shoreline residential development. Therefore, restricted access could pose problems to navigation which may be unacceptable.

The placement of a barrage at the entrance to a coastal basin could alter the flow regime. Consequently environmental impacts would be expected on salmon migrating through the basin to spawning streams, on marine mammals frequenting the basin and on kelp beds near the basin entrance. Kelp beds provide protection for juvenile fish. A barrage could potentially alter the marine ecology of the basin because of changes in the exchange of nutrients between the basin and the ocean. The extent of the effect would depend primarily upon the turbine design. While no data on the fisheries impact for the low head vertical axis water turbine is available, it is expected that a barrage design incorporating this type of turbine would reduce the numbers of salmon returning to the spawning area. Other turbine designs suitable for higher head applications would eliminate any natural migration of fish to or from the basin. Impacts in this case would be determined by the size of the affected fisheries resource. Mitigation of or compensation for impacts on the salmon fishery would likely involve a salmon enhancement program.

(c) Wind

Along the west coast of British Columbia suitable locations for wind power development are generally found at higher elevations on exposed hills.

Wind farm development requires the use of large areas cleared of forest growth. The land requirements depend on the number of machines to be erected; however, it would not be uncommon to alienate more than 100 ha for a large wind farm. Some of the most suitable locations in B.C. are on hill tops which have been logged. These cleared areas complete with access roads make ideal sites; however, commercial logging operations would no longer have the use of this land for timber production.

Other impacts may result from noise generated by the wind machines. If wind farms are placed along bird migration routes, the noise and turbulence from the wind turbines could frighten these birds and adversely affect their migration. Noise from the wind machines could also be unpleasant for people who may live or work nearby.

(d) Thermal

Various fuels including wood (wood waste, tree farm), municipal solid waste, peat and coal could be used to generate electrical energy on a small scale. The conventional method of utilizing these fuels involves the direct firing of the fuel in a boiler to generate steam which is then used to drive a turbine-generator. Alternately, the fuel could be used to produce a combustible gas which would by either fired in a steam boiler, an internal combustion engine or a gas turbine.

Environmental concerns would arise from the emissions of air contaminants as well as from water effluents and solid wastes. The provincial Waste Management Act (1982) defines the process whereby wastes are permitted for release to the environment.

Air contaminants would include products of combustion which are a characteristic of the fuel. Small quantities of nitrogen oxides (NO_x), sulphur dioxide (SO_2), organic matter, and ash would be released from an elevated stack.

Water would be used in the powerplant as a coolant. Cooling water from a small facility (several megawatts) is usually discharged to a larger body of water with the requirement that the temperature rise in the receiving waters beyond the immediate zone of influence would not be greater than 1°C.

Solid waste from a small thermal facility consists of the ash from the boiler or gasification process. This material is usually taken to a local landfill for disposal.

The activity associated with obtaining and handling the fuel for a thermal plant could have important socio-economic influences. If wood (waste wood or tree farm) is the primary fuel, a significant amount of local labour would be required. This would likely be viewed as a benefit from a wood-fired thermal project.

The operation of a tree farm to supply wood fuel would require large amounts of dedicated land. Based on a 10-year growing cycle approximately 2400 ha would be required to provide fuel for a 2 MW wood-fired thermal generating station. Depending on the area, land use conflicts could arise with other resource users.

Fuel handling at the thermal plant site would involve stockpiling and recovery operations. The use of wood requires a logging operation which would be the source of some noise. Hogging could be done in the bush at the source of the fuel or alternately, if there are a number of fuel sources, it may be more practical to hog the wood at the powerplant site. The choice of haul routes from the fuel source to the powerplant site would require planning to minimize effects on other users of the haul routes as well as on those persons living along the routes. Coal would be transported to the powerplant site by barge and a suitable off-loading facility would be required.

(e) Transmission or Distribution

Transmission or distribution systems are an important component of each generating facility. The cost of the systems and their environmental impact are proportional to the length of the transmission or distribution line. In many cases where small, remote generating facilities are being considered, transmission or distribution costs limit project feasibility. Bamfield and Bella Bella could potentially be connected to existing generating facilities (Bella Bella to Ocean Falls) or the grid system (Bamfield to Port Alberni).

Environmental impacts of transmission or distribution line development are primarily associated with land use conflicts. This type of impact is site specific, but may have some of the following effects:

1. Right-of-ways may interfere with timber leases by hampering access to logging areas.
2. Changes in wildlife habitat may result from right-of-way development and this in turn could impact on established traplines and hunting territories.
3. The visual impact of a transmission or distribution line and right-of-way may affect the value of an area for recreation and tourism by disturbing the pristine nature of the landscape.

The above impacts would generally complicate development; however, in most cases mitigation and compensation plans would alleviate impacts.

It is desirable where possible to use existing right-of-ways (roadways) for routing transmission or distribution lines. In these cases the added impact of a wood pole transmission or distribution line is minimal because there would be no major land use conflicts.

The effects of transmission or distribution line construction on fish and wildlife must also be considered. Fishing forms an important component of the economy of the study areas. In general, the rivers and streams in the study areas provide spawning and rearing habitat for anadromous fish, although the lengths of many of the spawning beds are limited because of barriers to migration and lack spawning habitat beyond these barriers. Fisheries concerns arise with respect to the location, construction, and maintenance of transmission or distribution line right-of-ways. The most common concern arises from the loss of fisheries habitat due to access road development, the clearing within riparian areas and the timing of construction activities.

The heavy rainfall which occurs in the study areas creates a greater need for managing water runoff and river sedimentation, particularly in those areas potentially affecting streams with high fisheries values.

More site specific information would be required during detailed route selection studies to assess the quality of a salmon stream, critical habitat, and timing constraints. Several guidelines and standards for water crossings and powerline clearing are available for route planning and construction specifications.[1,2] In addition the provincial Ministry of Environment is producing a set of technical objectives of environmental standards for water crossings.[3]

Changes in wildlife habitat resulting from right-of-way construction may affect some large mammals including ungulates and small fur bearers. These effects are less important than potential fisheries impacts. It is likely that measures employed to reduce disturbances to salmon streams for fisheries purposes would also protect the streams for other wildlife uses.

(f) Mining

Impacts of alternative energy development on most environmental resources are restricted to the sites of those resources, but effects on mining may be felt where there is only an area of favorable geology. In order to provide the background information on mining and economic geology these resources have been treated separately from other environmental resources in this report.

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APPENDIX C

PARAMETERS FOR COST ESTIMATES

C.1 INTRODUCTION

A computer program was developed by the System Studies Section of the Generation Planning Department of B.C. Hydro. This program was used to compare gross unit energy costs of alternative energy projects. The parameters which are used in the program are summarized in Appendix C. The gross unit energy cost is used in this report to examine relative costs of alternatives in 1990/91.

C.2 ESTIMATING PARAMETERS

Cost estimates are based on inflation values listed in Section 3.0 in the main text of this report. Capital recovery factors were determined by assuming discount rates of 4, 6, 8 and 10 percent net of inflation. Interest during construction (IDC) was similarly calculated at 4, 6, 8 and 10 percent net of inflation.

Construction costs for plants and substations were estimated for each alternative. These estimates assumed a suitable site would be available and that no extraordinary amount of site preparation would be required. Transmission costs for a 266.8 kcmil wood pole line were assumed to be $85,500/km including surveys, clearing (20 m wide), material, labor and right-of-way aquisition. Similarly, the cost of a 25 kV, 3-phase, 266.8 kcmil, wood pole distribution line was assumed to cost between $34,000 and $50,000/km depending on accessibility and topography. Other items which could affect the cost of a 25 kV line such as depth to bedrock and span length were not considered in the estimate. The above cost excludes right-of-way acquisition and clearing which tended to increase all distribution estimates toward the top end of the range.

The project cost ($/kW) is the ratio of the sum of the costs of construction, engineering and contingency to the plant capacity.

Corporate overhead for B.C. Hydro is estimated to be 9 percent of the project cost which includes the construction cost, engineering and contingency. For this study corporate overhead was applied at this rate to all projects regardless of size.

Contingencies were applied at different rates for different projects depending on the quality of the estimates. Some project cost estimates such as small hydroelectric are very site specific and little is known about these sites; therefore, it was necessary to impose a large contingency. Similarly, some technologies for electrical power generation (e.g. tidal) are not proven and may also be very site specific; therefore, a large contingency is required.

A summary of the basis for estimating operating costs is provided in Table AC2-1. Fixed charges are estimated as percentages of the construction cost including engineering and contingency. The variable charges are estimated in mills/kW·h.

Fuel costs apply to potential diesel and thermal projects. Diesel fuel (No. 2 fuel oil) costs include the cost of lube oil and all taxes and delivery charges. The costs of coal and wood fuels also include delivery charges and electrical requirements for station operation. The latter is reflected in the heat rate or efficiency which relates to overall electrical efficiency from fuel in to electricity out.

The total annual cost is the sum of the capital recovery, operation and maintenance, taxes and fuel costs (where applicable).

The cost per kilowatt-hour or gross unit energy cost is the total annual cost divided by the usable energy.

C.3 DISCUSSION

Although the gross unit energy cost has been used in this report as the initial method of comparing the benefits among several projects, there are other factors which are also used to determined the suitability of a project for development. These factors include capital requirements, which are particularly important when interest rates are high or when borrowing is at a high level because of rapid growth.

The "payback period" is used in this report in order to select the most suitable alternative from the projects which are estimated to have gross unit energy costs which could be more economical than diesel generation. The payback period for a new plant serving a remote community is not derived by the conventional method of examining the time required for net profit to offset the capital cost. For a remote community it is necessary to view the reduction in annual losses as the net savings. The discounted net savings and their cumulative totals are estimated for each year. In this report the number of years required for the cumulative total to equal the capital cost is defined as the "payback period".

TABLE AC2-1

BASIS FOR ESTIMATING OPERATING COSTS
(March, 1984)

	Small Hydroelectric	Tidal	Wind	Thermal (Coal and Wood)	Wood Gasification	Substations	Transmission (Wood Pole)
1. **Fixed Charges**							
(Percent of uninflated total construction cost including engineering and contingency.)							
Operation and Maintenance	0.45	1.20	2.00	6.30	5.20	0.80	1.90
Administration and General Expense	incl.	incl.	incl.	incl.	incl.	incl.	incl.
Insurance	0.03	incl.	incl.	incl.	incl.	incl.	incl.
Grants and Taxes	1.33	1.33	incl.	1.33	0.98	1.70	1.70
Interim Replacement	incl.	incl.	incl.	incl.	incl.	incl.	incl.
Total	1.81	2.53	2.00	7.63	6.18	2.50	3.60
2. Variable Charges (mills/kW·h)	4.10	-	-	0.14	0.70	-	-
3. Assumed Plant Life (a)	40	40	20	35	20	30	30

APPENDIX D

ENERGY COSTS - BAMFIELD

D.1 INTRODUCTION

The computer program described in Appendix C was developed by B.C. Hydro in order to improve flexibility in making comparisons among alternatives. The alternatives were compared at 4, 6, 8 and 10 percent net discount rates. The resulting energy costs are summarized in Table AD1-1. The energy costs at a 4 percent net discount rate, which is used in B.C. Hydro studies, range from 104 mills/kW·h for small hydro to 872 mills/kW·h for wind. Similarly, at a 10 percent net discount rate the energy costs range from 159 mills/kW·h for a distribution line from Port Alberni to 1290 mills/kW·h for wind. The relative changes in energy costs with discount rate reflects the relative variation in capital cost at a constant annual energy. The higher discount rates penalize alternatives which have a high capital cost relative to annual fuel and operating costs. For fuel savers the cost of energy should be compared to the equivalent incremental energy cost for diesel fuel which is 117 mills/kW·h (December 1983).

Section D.2 consists of computer printouts which list peak capacity, firm energy, secondary energy, construction costs, contingencies, overhead, project life, fixed operating and maintenance costs, taxes and variable charges (e.g. the cost of electricity and water licence fees). For thermal alternatives, fuel costs are listed for various discount rates; the heating value, heat rate or efficiency, fuel cost and fuel consumption are also listed. For each discount rate the last table lists all of the computed costs in thousands of dollars as well as the capital cost per kilowatt and the gross unit energy cost in mills/kW·h.

TABLE AD1-1

UNIT ENERGY COST COMPARISONS AT VARIOUS NET INTEREST RATES - BAMFIELD

	Diesel[*1] Bamfield	Small Hydroelectric Sarita River	Tidal Bamfield Inlet	Wind Pachena	Thermal			Distribution Port Alberni Bamfield
					Wood Roquefeuil Bay	Wood-gas Roquefeuil Bay	Coal Roquefeuil Bay	
Peak Capacity (MW)	1.70	1.00	0.50	0.30	1.00	1.00	1.00	1.80
Annual Energy (GW·h)	4.65	4.65	1.40	0.16	4.65	4.65	4.65	4.65
Energy Cost (mills/kW·h) at 4% net	161	104	416	872	253	232	193	118
Energy Cost (mills/kW·h) at 6% net	164	127	509	1001	281	253	215	131
Energy Cost (mills/kW·h) at 8% net	168	152	611	1141	311	275	240	144
Energy Cost (mills/kW·h) at 10% net	172	178	720	1290	345	299	266	159

[*1] The equivalent energy cost of No. 2 fuel oil delivered to Bamfield is estimated to be 117 mills/kW·h.

D.2 BAMFIELD DIESEL[*1]

Project Capability

Peak capacity (MW)	1.70
Firm energy (GW·h)	4.65
Secondary energy (GW·h)	0.00

Costs for Bamfield Diesel
(Discount Rate 4% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1207	-	-	1207
Cost per kilowatt ($/kW)	710	-	-	710

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	89	-	-	89
Operation and maintenance	95	-	-	95
School taxes	18	-	-	18
Fuel costs	546			546
Total annual cost	748	-	-	748
Cost per kW·h (mills/kW·h)	160.86	-	-	160.86

[*1] Contains some station costs not included in other alternatives, but these are assumed to be small relative to the overall costs.

Costs for Bamfield Diesel
(Discount Rate 6% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1207	-	-	1207
Cost per kilowatt ($/kW)	710	-	-	710

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	105	-	-	105
Operation and maintenance	95	-	-	95
School taxes	18	-	-	18
Fuel costs	546			546
Total annual cost	764	-	-	764
Cost per kW·h (mills/kW·h)	164.30	-	-	164.30

Costs for Bamfield Diesel
(Discount Rate 8% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1207	-	-	1207
Cost per kilowatt ($/kW)	710	-	-	710

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	123	-	-	123
Operation and maintenance	95	-	-	95
School taxes	18	-	-	18
Fuel costs	546			546
Total annual cost	782	-	-	782
Cost per kW·h (mills/kW·h)	168.17	-	-	168.17

Costs for Bamfield Diesel
(Discount Rate 10% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1207	-	-	1207
Cost per kilowatt ($/kW)	710	-	-	710

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	142	-	-	142
Operation and maintenance	95	-	-	95
School taxes	18	-	-	18
Fuel costs	546			546
Total annual cost	801	-	-	801
Cost per kW·h (mills/kW·h)	172.26	-	-	172.26

D.2.2. Bamfield Small Hydroelectric

```
                    Project Evaluation Package              MAR 29 1984

Project Data For:         BAMFIELD SARITA

Project Capability
   Peak Capacity        (MW)              1.00
   Firm Energy          (GW.h)             .00
   Secondary Energy     (GW.h)            4.65

Notes on Project Data
```

```
                    Project Evaluation Package              MAR 29 1984
               Capital Cost Information for BAMFIELD SARITA

                    Construction  Contingency  Overhead   Cost   Project
                    Cost(K$)      Allowance(%) Rate(%)    Distr.  Life
Generation
   Cost 1               3437        35.00        9.00       1      40
Transmission
   500 kV                  0          .00         .00       0       0
   360 kV                  0          .00         .00       0       0
   230 kV                  0          .00         .00       0       0
   132 kV                  0          .00         .00       0       0
    60 kV                  0          .00         .00       0       0
    25 kV                915        20.00        9.00      22      30
Substation
   500 kV                  0          .00         .00       0       0
   360 kV                  0          .00         .00       0       0
   230 kV                  0          .00         .00       0       0
   132 kV                  0          .00         .00       0       0
    60 kV                  0          .00         .00       0       0
    25 kV                150        10.00        9.00      20      30
```

```
                    Project Evaluation Package              MAR 29 1984
              Operating Cost Information for BAMFIELD SARITA

                    Fixed O & M    Taxes    Fixed Charge Variable Charges
                     % of CC      % of CC     $ / MW       mills/kW.h
Generation
   Cost 1              .48          1.33        .00          4.10
Transmission
   500 kV              .00           .00        .00           .00
   360 kV              .00           .00        .00           .00
   230 kV              .00           .00        .00           .00
   132 kV              .00           .00        .00           .00
    60 kV              .00           .00        .00           .00
    25 kV             1.90          1.70        .00           .00
Substation
   500 kV              .00           .00        .00           .00
   360 kV              .00           .00        .00           .00
   230 kV              .00           .00        .00           .00
   132 kV              .00           .00        .00           .00
    60 kV              .00           .00        .00           .00
    25 kV              .80          1.70        .00           .00
```

Project Evaluation Package MAR 29 1984

Costs for BAMFIELD SARITA

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	3437	915	150	4502
Contingency Allowance	1203	183	15	1401
Overhead Allowance	418	99	15	531
Interest During Const.	67	0	3	70
Total Capital Cost	5125	1197	183	6505
Cost per KiloWatt ($/KW)	5125	1197	183	6505
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	259	69	11	339
Operation & Maintenance	41	21	1	64
School Taxes	62	19	3	83
Fuel Costs	0	0	0	0
Total Annual Cost	362	109	15	485
Cost per KW.h (mills/kW.h)	77.84	23.38	3.16	104.39

4%

Project Evaluation Package MAR 29 1984

Costs for BAMFIELD SARITA

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	3437	915	150	4502
Contingency Allowance	1203	183	15	1401
Overhead Allowance	418	99	15	531
Interest During Const.	101	0	5	106
Total Capital Cost	5159	1197	184	6540
Cost per KiloWatt ($/KW)	5159	1197	184	6540
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	343	87	13	443
Operation & Maintenance	41	21	1	64
School Taxes	62	19	3	83
Fuel Costs	0	0	0	0
Total Annual Cost	446	126	18	590
Cost per KW.h (mills/kW.h)	95.89	27.20	3.77	126.86

6%

Project Evaluation Package MAR 29 1984

Costs for BAMFIELD SARITA

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	3437	915	150	4502
Contingency Allowance	1203	183	15	1401
Overhead Allowance	418	99	15	531
Interest During Const.	135	0	6	141
Total Capital Cost	5192	1197	186	6575
Cost per KiloWatt ($/KW)	5192	1197	186	6575
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	435	106	17	558
Operation & Maintenance	41	21	1	64
School Taxes	62	19	3	83
Fuel Costs	0	0	0	0
Total Annual Cost	538	146	21	705
Cost per KW.h (mills/kW.h)	115.80	31.36	4.44	151.60

8%

Project Evaluation Package MAR 29 1984

Costs for BAMFIELD SARITA

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	3437	915	150	4502
Contingency Allowance	1203	183	15	1401
Overhead Allowance	418	99	15	531
Interest During Const.	168	0	8	176
Total Capital Cost	5226	1197	187	6610
Cost per KiloWatt ($/KW)	5226	1197	187	6610
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	534	127	20	681
Operation & Maintenance	41	21	1	64
School Taxes	62	19	3	83
Fuel Costs	0	0	0	0
Total Annual Cost	637	166	24	828
Cost per KW.h (mills/kW.h)	137.39	35.80	5.16	178.35

10%

D.2.3. Bamfield Tidal

Project Evaluation Package MAR 23 1984

Project Data For: BAMFIELD INLET TIDAL

Project Capability		
Peak Capacity	(MW)	.50
Firm Energy	(GW.h)	.00
Secondary Energy	(GW.h)	1.40

Notes on Project Data

Project Evaluation Package MAR 23 1984
Capital Cost Information for BAMFIELD INLET TIDAL

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	5958	20.00	9.00	18	40
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	34	10.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	0	.00	.00	0	0

Project Evaluation Package MAR 23 1984
Operating Cost Information for BAMFIELD INLET TIDAL

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Varicble Charges mills/kW.h
Generation				
Cost 1	1.20	1.33	.00	.00
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.00	.00	.00	.00

```
                         Project Evaluation Package              MAR 23 1984

            Costs for        BAMFIELD INLET TIDAL

Capital Cost Summary (K$)                    Gener.    Trans.    Subst.    Total
   Construction Cost                          5958        34         0     5992
   Contingency Allowance                      1192         3         0     1195
   Overhead Allowance                          643         3         0      647
   Interest During Const.                       94         0         0       94
   Total Capital Cost                         7887        41         0     7927
   Cost per KiloWatt ($/KW)                  15773        82         0    15855

Annual Cost Summary (K$)                     Gener.    Trans.    Subst.    Total
   Capital Recovery                            398         2         0      401
   Operation & Maintenance                      86         1         0       87
   School Taxes                                 95         1         0       96
   Fuel Costs                                    0         0         0        0
   Total Annual Cost                           579         4         0      583
   Cost per KW.h (mills/kW.h)               413.82      2.65       .00   416.46
```

4%

```
                         Project Evaluation Package              MAR 23 1984

            Costs for        BAMFIELD INLET TIDAL

Capital Cost Summary (K$)                    Gener.    Trans.    Subst.    Total
   Construction Cost                          5958        34         0     5992
   Contingency Allowance                      1192         3         0     1195
   Overhead Allowance                          643         3         0      647
   Interest During Const.                      140         0         0      140
   Total Capital Cost                         7933        41         0     7974
   Cost per KiloWatt ($/KW)                  15867        82         0    15948

Annual Cost Summary (K$)                     Gener.    Trans.    Subst.    Total
   Capital Recovery                            527         3         0      530
   Operation & Maintenance                      86         1         0       87
   School Taxes                                 95         1         0       96
   Fuel Costs                                    0         0         0        0
   Total Annual Cost                           708         4         0      712
   Cost per KW.h (mills/kW.h)               505.82      3.08       .00   508.90
```

6%

```
                         Project Evaluation Package              MAR 23 1984

            Costs for        BAMFIELD INLET TIDAL

Capital Cost Summary (K$)                    Gener.    Trans.    Subst.    Total
   Construction Cost                          5958        34         0     5992
   Contingency Allowance                      1192         3         0     1195
   Overhead Allowance                          643         3         0      647
   Interest During Const.                      187         0         0      187
   Total Capital Cost                         7980        41         0     8021
   Cost per KiloWatt ($/KW)                  15960        82         0    16042

Annual Cost Summary (K$)                     Gener.    Trans.    Subst.    Total
   Capital Recovery                            669         4         0      673
   Operation & Maintenance                      86         1         0       87
   School Taxes                                 95         1         0       96
   Fuel Costs                                    0         0         0        0
   Total Annual Cost                           850         5         0      855
   Cost per KW.h (mills/kW.h)               607.21      3.55       .00   610.76
```

8%

```
                         Project Evaluation Package              MAR 23 1984

            Costs for        BAMFIELD INLET TIDAL

Capital Cost Summary (K$)                    Gener.    Trans.    Subst.    Total
   Construction Cost                          5958        34         0     5992
   Contingency Allowance                      1192         3         0     1195
   Overhead Allowance                          643         3         0      647
   Interest During Const.                      234         0         0      234
   Total Capital Cost                         8027        41         0     8068
   Cost per KiloWatt ($/KW)                  16054        82         0    16135

Annual Cost Summary (K$)                     Gener.    Trans.    Subst.    Total
   Capital Recovery                            821         4         0      825
   Operation & Maintenance                      86         1         0       87
   School Taxes                                 95         1         0       96
   Fuel Costs                                    0         0         0        0
   Total Annual Cost                          1002         6         0     1007
   Cost per KW.h (mills/kW.h)               715.50      4.05       .00   719.56
```

10%

D.2.4. Bamfield Wind

```
                    Project Evaluation Package            MAR 23 1984

Project Data For:       BAMF WIND 50

Project Capability
   Peak Capacity      (MW)             .25
   Firm Energy       (GW.h)            .00
   Secondary Energy  (GW.h)            .13

Notes on Project Data
```

```
                    Project Evaluation Package            MAR 23 1984
              Capital Cost Information for BAMF WIND 50

                Construction  Contingency  Overhead   Cost   Project
                  Cost(K$)    Allowance(%)  Rate(%)   Distr.   Life
Generation
   Cost 1           1005        10.00        9.00       22      20
Transmission
   500 kV              0          .00         .00        0       0
   360 kV              0          .00         .00        0       0
   230 kV              0          .00         .00        0       0
   132 kV              0          .00         .00        0       0
    60 kV              0          .00         .00        0       0
    25 kV             60        10.00        9.00       22      30
Substation
   500 kV              0          .00         .00        0       0
   360 kV              0          .00         .00        0       0
   230 kV              0          .00         .00        0       0
   132 kV              0          .00         .00        0       0
    60 kV              0          .00         .00        0       0
    25 kV              0          .00         .00        0       0
```

```
                    Project Evaluation Package            MAR 23 1984
             Operating Cost Information for BAMF WIND 50

                   Fixed O & M    Taxes   Fixed Charge Variable Charges
                    % of CC      % of CC     $ / MW      mills/kW.h
Generation
   Cost 1             2.00         .00         .00          .00
Transmission
   500 kV              .00         .00         .00          .00
   360 kV              .00         .00         .00          .00
   230 kV              .00         .00         .00          .00
   132 kV              .00         .00         .00          .00
    60 kV              .00         .00         .00          .00
    25 kV             1.90        1.70         .00          .00
Substation
   500 kV              .00         .00         .00          .00
   360 kV              .00         .00         .00          .00
   230 kV              .00         .00         .00          .00
   132 kV              .00         .00         .00          .00
    60 kV              .00         .00         .00          .00
    25 kV              .00         .00         .00          .00
```

Project Evaluation Package MAR 23 1984

Costs for BAMF WIND 50

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	1005	60	0	1065
Contingency Allowance	100	6	0	106
Overhead Allowance	99	6	0	105
Interest During Const.	0	0	0	0
Total Capital Cost	1205	72	0	1277
Cost per KiloWatt ($/KW)	4820	288	0	5108

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	89	4	0	93
Operation & Maintenance	22	1	0	23
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	111	7	0	117
Cost per KW.h (mills/kW.h)	852.12	50.28	.00	902.40

4%

Project Evaluation Package MAR 23 1984

Costs for BAMF WIND 50

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	1005	60	0	1065
Contingency Allowance	100	6	0	106
Overhead Allowance	99	6	0	105
Interest During Const.	0	0	0	0
Total Capital Cost	1205	72	0	1277
Cost per KiloWatt ($/KW)	4820	288	0	5108

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	105	5	0	110
Operation & Maintenance	22	1	0	23
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	127	8	0	135
Cost per KW.h (mills/kW.h)	978.21	58.48	.00	1036.69

6%

Project Evaluation Package MAR 23 1984

Costs for BAMF WIND 50

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	1005	60	0	1065
Contingency Allowance	100	6	0	106
Overhead Allowance	99	6	0	105
Interest During Const.	0	0	0	0
Total Capital Cost	1205	72	0	1277
Cost per KiloWatt ($/KW)	4820	288	0	5108

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	123	6	0	129
Operation & Maintenance	22	1	0	23
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	145	9	0	154
Cost per KW.h (mills/kW.h)	1114.16	67.43	.00	1181.60

8%

Project Evaluation Package MAR 23 1984

Costs for BAMF WIND 50

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	1005	60	0	1065
Contingency Allowance	100	6	0	106
Overhead Allowance	99	6	0	105
Interest During Const.	0	0	0	0
Total Capital Cost	1205	72	0	1277
Cost per KiloWatt ($/KW)	4820	288	0	5108

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	142	8	0	149
Operation & Maintenance	22	1	0	23
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	164	10	0	174
Cost per KW.h (mills/kW.h)	1258.83	76.98	.00	1335.81

10%

D.2.5. Bamfield Wood Thermal

Project Evaluation Package MAR 28 1984

Project Data For: BAMFIELD WOOD THERM.

Project Capability

Peak Capacity	(MW)	1.00
Firm Energy	(GW.h)	4.65
Secondary Energy	(GW.h)	.00

Notes on Project Data

Project Evaluation Package MAR 28 1984
Capital Cost Information for BAMFIELD WOOD THERM.

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	5372	10.00	9.00	8	35
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	225	10.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	290	10.00	9.00	20	30

Project Evaluation Package MAR 28 1984
Operating Cost Information for BAMFIELD WOOD THERM.

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Variable Charges mills/kW.h
Generation				
Cost 1	.88	1.33	.00	.14
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.80	1.70	.00	.00

```
                        Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BAMFIELD WOOD THERM.

Unit Fuel Cost   ($/GJ) ==>              .00
               ($/tonne) ==>            69.15
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate       (GJ/GWh) ==>         16440.00     4%
Efficiency           (%) ==>              .00

Fuel Cost  (mills/kW.h) ==>             67.91
Fuel Consumption (kt/a) ==>              4.57
```

```
                        Project Evaluation Package              MAR 28 1984

              Costs for         BAMFIELD WOOD THERM.

Capital Cost Summary (K$)                 Gener.    Trans.    Subst.    Total
   Construction Cost                        5372       225       290     5887
   Contingency Allowance                     537        22        29      589
   Overhead Allowance                        532        22        29      583
   Interest During Const.                    191         0         6      196
   Total Capital Cost                       6632       270       354     7255
   Cost per KiloWatt ($/KW)                 6632       270       354     7255

Annual Cost Summary (K$)                  Gener.    Trans.    Subst.    Total
   Capital Recovery                          355        16        20      391
   Operation & Maintenance                    53         5         3       60
   School Taxes                               79         4         5       88
   Fuel Costs                                316         0         0      316
   Total Annual Cost                         802        25        28      855
   Cost per KW.h (mills/kW.h)             172.55      5.27      6.11   183.93
```

```
                        Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BAMFIELD WOOD THERM.

Unit Fuel Cost   ($/GJ) ==>              .00
               ($/tonne) ==>            71.50
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate       (GJ/GWh) ==>         16440.00     6%
Efficiency           (%) ==>              .00

Fuel Cost  (mills/kW.h) ==>             70.22
Fuel Consumption (kt/a) ==>              4.57
```

```
                        Project Evaluation Package              MAR 28 1984

              Costs for         BAMFIELD WOOD THERM.

Capital Cost Summary (K$)                 Gener.    Trans.    Subst.    Total
   Construction Cost                        5372       225       290     5867
   Contingency Allowance                     537        22        29      589
   Overhead Allowance                        532        22        29      583
   Interest During Const.                    286         0         9      295
   Total Capital Cost                       6727       270       356     7353
   Cost per KiloWatt ($/KW)                 6727       270       356     7353

Annual Cost Summary (K$)                  Gener.    Trans.    Subst.    Total
   Capital Recovery                          464        20        26      509
   Operation & Maintenance                    53         5         3       60
   School Taxes                               79         4         5       88
   Fuel Costs                                327         0         0      327
   Total Annual Cost                         922        29        34      984
   Cost per KW.h (mills/kW.h)             198.23      6.13      7.28   211.64
```

```
                    Project Evaluation Package              MAR 28 1984

 Fuel Cost Data for  BAMFIELD WOOD THERM.

 Unit Fuel Cost    ($/GJ) ==>            .00
                ($/tonne) ==>          73.95
 Calorific Value (MJ/Kg) ==>           16.74

 Heat Rate        (GJ/GWh) ==>       16440.00
 Efficiency           (%) ==>            .00

 Fuel Cost  (mills/kW.h) ==>           72.62
 Fuel Consumption (kt/a) ==>            4.57
```

8 %

```
                    Project Evaluation Package              MAR 28 1984

              Costs for         BAMFIELD WOOD THERM.

 Capital Cost Summary (K$)               Gener.   Trans.   Subst.   Total
    Construction Cost                      5372      225      290    5387
    Contingency Allowance                   537       22       29     589
    Overhead Allowance                      532       22       29     583
    Interest During Const.                  381        0       12     393
    Total Capital Cost                     6822      270      359    7452
    Cost per KiloWatt ($/KW)               6822      270      359    7452

 Annual Cost Summary (K$)                Gener.   Trans.   Subst.   Total
    Capital Recovery                        585       24       32     641
    Operation & Maintenance                  53        5        3      60
    School Taxes                             79        4        5      88
    Fuel Costs                              338        0        0     338
    Total Annual Cost                      1054       33       40    1127
    Cost per KW.h (mills/kW.h)           226.74     7.07     8.58  242.39
```

```
                    Project Evaluation Package              MAR 28 1984

 Fuel Cost Data for  BAMFIELD WOOD THERM.

 Unit Fuel Cost    ($/GJ) ==>            .00
                ($/tonne) ==>          76.55
 Calorific Value (MJ/Kg) ==>           16.74

 Heat Rate        (GJ/GWh) ==>       16440.00
 Efficiency           (%) ==>            .00

 Fuel Cost  (mills/kW.h) ==>           75.18
 Fuel Consumption (kt/a) ==>            4.57
```

10 %

```
                    Project Evaluation Package              MAR 28 1984

              Costs for         BAMFIELD WOOD THERM.

 Capital Cost Summary (K$)               Gener.   Trans.   Subst.   Total
    Construction Cost                      5372      225      290    5887
    Contingency Allowance                   537       22       29     589
    Overhead Allowance                      532       22       29     583
    Interest During Const.                  477        0       15     491
    Total Capital Cost                     6918      270      362    7550
    Cost per KiloWatt ($/KW)               6918      270      362    7550

 Annual Cost Summary (K$)                Gener.   Trans.   Subst.   Total
    Capital Recovery                        717       29       38     784
    Operation & Maintenance                  53        5        3      60
    School Taxes                             79        4        5      88
    Fuel Costs                              350        0        0     350
    Total Annual Cost                      1198       38       46    1282
    Cost per KW.h (mills/kW.h)           257.66     8.07     9.98  275.71
```

D.2.6. Bamfield Wood Gasification

Project Evaluation Package MAR 28 1984

Project Data For: BAMFIELD WOOD GAS

Project Capability

Peak Capacity	(MW)	1.00
Firm Energy	(GW.h)	4.65
Secondary Energy	(GW.h)	.00

Notes on Project Data

Project Evaluation Package MAR 28 1984

Capital Cost Information for BAMFIELD WOOD GAS

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	4136	10.00	9.00	10	20
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	225	10.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	290	10.00	9.00	20	30

Project Evaluation Package MAR 28 1984

Operating Cost Information for BAMFIELD WOOD GAS

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Variable Charges mills/kW.h
Generation				
Cost 1	5.20	.98	.00	.70
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.80	1.70	.00	.00

```
                         Project Evaluation Package            MAR 28 1984
   Fuel Cost Data for  BAMFIELD WOOD GAS

   Unit Fuel Cost    ($/GJ) ==>            .00
                 ($/tonne) ==>           69.15
   Calorific Value (MJ/Kg) ==>           16.74

   Heat Rate      (GJ/GWh) ==>        19250.00      4%
   Efficiency          (%) ==>             .00

   Fuel Cost  (mills/kW.h) ==>           79.52
   Fuel Consumption (kt/a) ==>            5.35
```

```
                         Project Evaluation Package            MAR 28 1984
         Costs for          BAMFIELD WOOD GAS

   Capital Cost Summary (K$)           Gener.    Trans.    Subst.    Total
      Construction Cost                  4136       225       290     4651
      Contingency Allowance               414        22        29      465
      Overhead Allowance                  409        22        29      460
      Interest During Const.              103         0         6      109
      Total Capital Cost                 5062       270       354     5686
      Cost per KiloWatt ($/KW)           5062       270       354     5686

   Annual Cost Summary (K$)            Gener.    Trans.    Subst.    Total
      Capital Recovery                    372        16        20      409
      Operation & Maintenance             240         5         3      247
      School Taxes                         45         4         5       54
      Fuel Costs                          370         0         0      370
      Total Annual Cost                  1027        25        28     1080
      Cost per KW.h (mills/kW.h)       220.79      5.27      6.11   232.17
```

```
                         Project Evaluation Package            MAR 28 1984
   Fuel Cost Data for  BAMFIELD WOOD GAS

   Unit Fuel Cost    ($/GJ) ==>            .00
                 ($/tonne) ==>           71.50
   Calorific Value (MJ/Kg) ==>           16.74

   Heat Rate      (GJ/GWh) ==>        19250.00      6%
   Efficiency          (%) ==>             .00

   Fuel Cost  (mills/kW.h) ==>           82.22
   Fuel Consumption (kt/a) ==>            5.35
```

```
                         Project Evaluation Package            MAR 28 1984
         Costs for          BAMFIELD WOOD GAS

   Capital Cost Summary (K$)           Gener.    Trans.    Subst.    Total
      Construction Cost                  4136       225       290     4651
      Contingency Allowance               414        22        29      465
      Overhead Allowance                  409        22        29      460
      Interest During Const.              155         0         9      163
      Total Capital Cost                 5114       270       356     5740
      Cost per KiloWatt ($/KW)           5114       270       356     5740

   Annual Cost Summary (K$)            Gener.    Trans.    Subst.    Total
      Capital Recovery                    446        20        26      491
      Operation & Maintenance             240         5         3      247
      School Taxes                         45         4         5       54
      Fuel Costs                          382         0         0      382
      Total Annual Cost                  1113        29        34     1175
      Cost per KW.h (mills/kW.h)       239.27      6.13      7.28   252.68
```

```
                    Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BAMFIELD WOOD GAS


Unit Fuel Cost    ($/GJ) ==>               .00
               ($/tonne) ==>             73.95
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate      (GJ/GWh) ==>          19250.00        8%
Efficiency          (%) ==>               .00

Fuel Cost  (mills/kW.h) ==>             85.04
Fuel Consumption (kt/a) ==>              5.35
```

```
                    Project Evaluation Package              MAR 28 1984

              Costs for        BAMFIELD WOOD GAS

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                      4136       225       290     4651
   Contingency Allowance                   414        22        29      465
   Overhead Allowance                      409        22        29      460
   Interest During Const.                  206         0        12      218
   Total Capital Cost                     5165       270       359     5795
   Cost per KiloWatt ($/KW)               5165       270       359     5795

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                        526        24        32      582
   Operation & Maintenance                 240         5         3      247
   School Taxes                             45         4         5       54
   Fuel Costs                              395         0         0      395
   Total Annual Cost                      1206        33        40     1279
   Cost per KW.h (mills/kW.h)           259.34      7.07      8.58   274.99
```

```
                    Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BAMFIELD WOOD GAS


Unit Fuel Cost    ($/GJ) ==>               .00
               ($/tonne) ==>             76.55
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate      (GJ/GWh) ==>          19250.00        10%
Efficiency          (%) ==>               .00

Fuel Cost  (mills/kW.h) ==>             88.03
Fuel Consumption (kt/a) ==>              5.35
```

```
                    Project Evaluation Package              MAR 28 1984

              Costs for        BAMFIELD WOOD GAS

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                      4136       225       290     4651
   Contingency Allowance                   414        22        29      465
   Overhead Allowance                      409        22        29      460
   Interest During Const.                  258         0        15      272
   Total Capital Cost                     5217       270       362     5849
   Cost per KiloWatt ($/KW)               5217       270       362     5849

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                        613        29        38      680
   Operation & Maintenance                 240         5         3      247
   School Taxes                             45         4         5       54
   Fuel Costs                              409         0         0      409
   Total Annual Cost                      1307        38        46     1390
   Cost per KW.h (mills/kW.h)           280.97      8.07      9.98   299.02
```

D.2.7. Bamfield Coal Thermal

Project Evaluation Package APR 10 1984

Project Data For: BAMFIELD COAL

Project Capability		
Peak Capacity	(MW)	1.00
Firm Energy	(GW.h)	4.65
Secondary Energy	(GW.h)	.00

Notes on Project Data

Project Evaluation Package APR 10 1984
Capital Cost Information for BAMFIELD COAL

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	4751	10.00	9.00	6	35
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	225	10.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	290	10.00	9.00	20	30

Project Evaluation Package APR 10 1984
Operating Cost Information for BAMFIELD COAL

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Variable Charges mills/kW.h
Generation				
Cost 1	.86	1.33	.00	.14
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.80	1.70	.00	.00

```
                         Project Evaluation Package             APR 10 1984

Fuel Cost Data for  BAMFIELD COAL

Unit Fuel Cost    ($/GJ) ==>                 .00
                ($/tonne) ==>              61.25
Calorific Value (MJ/Kg) ==>                25.75

Heat Rate       (GJ/GWh) ==>                 .00        4%
Efficiency           (%) ==>               29.15

Fuel Cost  (mills/kW.h) ==>                29.38
Fuel Consumption (kt/a) ==>                 2.23
```

```
                         Project Evaluation Package             APR 10 1984

                  Costs for        BAMFIELD COAL

Capital Cost Summary (K$)                   Gener.    Trans.    Subst.    Total
   Construction Cost                         4751       225       290      5266
   Contingency Allowance                      475        22        29       527
   Overhead Allowance                         470        22        29       521
   Interest During Const.                      91         0         6        97
   Total Capital Cost                        5788       270       354      6411
   Cost per KiloWatt ($/KW)                  5788       270       354      6411

Annual Cost Summary (K$)                    Gener.    Trans.    Subst.    Total
   Capital Recovery                           310        16        20       346
   Operation & Maintenance                     46         5         3        53
   School Taxes                                70         4         5        79
   Fuel Costs                                 137         0         0       137
   Total Annual Cost                          562        25        28       615
   Cost per KW.h (mills/kW.h)              120.81      5.27      6.11    132.20
```

```
                         Project Evaluation Package             APR 10 1984

Fuel Cost Data for  BAMFIELD COAL

Unit Fuel Cost    ($/GJ) ==>                 .00
                ($/tonne) ==>              61.55
Calorific Value (MJ/Kg) ==>                25.75

Heat Rate       (GJ/GWh) ==>                 .00        6%
Efficiency           (%) ==>               29.15

Fuel Cost  (mills/kW.h) ==>                29.52
Fuel Consumption (kt/a) ==>                 2.23
```

```
                         Project Evaluation Package             APR 10 1984

                  Costs for        BAMFIELD COAL

Capital Cost Summary (K$)                   Gener.    Trans.    Subst.    Total
   Construction Cost                         4751       225       290      5266
   Contingency Allowance                      475        22        29       527
   Overhead Allowance                         470        22        29       521
   Interest During Const.                     137         0         9       145
   Total Capital Cost                        5833       270       356      6459
   Cost per KiloWatt ($/KW)                  5833       270       356      6459

Annual Cost Summary (K$)                    Gener.    Trans.    Subst.    Total
   Capital Recovery                           402        20        26       448
   Operation & Maintenance                     46         5         3        53
   School Taxes                                70         4         5        79
   Fuel Costs                                 137         0         0       137
   Total Annual Cost                          655        29        34       717
   Cost per KW.h (mills/kW.h)              140.80      6.13      7.28    154.21
```

```
                         Project Evaluation Package             APR 10 1984

    Fuel Cost Data for  BAMFIELD COAL


    Unit Fuel Cost   ($/GJ) ==>                  .00
                  ($/tonne) ==>                61.90
    Calorific Value (MJ/Kg) ==>                25.75

    Heat Rate      (GJ/GWh) ==>                  .00      8%
    Efficiency          (%) ==>                29.15

    Fuel Cost  (mills/kW.h) ==>                29.69
    Fuel Consumption (kt/a) ==>                 2.23
```

```
                         Project Evaluation Package             APR 10 1984

                 Costs for        BAMFIELD COAL

    Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
       Construction Cost                     4751       225       290      5266
       Contingency Allowance                  475        22        29       527
       Overhead Allowance                     470        22        29       521
       Interest During Const.                 182         0        12       194
       Total Capital Cost                    5879       270       359      6508
       Cost per KiloWatt ($/KW)              5879       270       359      6508

    Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
       Capital Recovery                       504        24        32       560
       Operation & Maintenance                 46         5         3        53
       School Taxes                            70         4         5        79
       Fuel Costs                             138         0         0       138
       Total Annual Cost                      758        33        40       830
       Cost per KW.h (mills/kW.h)          162.92      7.07      8.58    178.57
```

```
                         Project Evaluation Package             APR 10 1984

    Fuel Cost Data for  BAMFIELD COAL


    Unit Fuel Cost   ($/GJ) ==>                  .00
                  ($/tonne) ==>                62.25
    Calorific Value (MJ/Kg) ==>                25.75

    Heat Rate      (GJ/GWh) ==>                  .00      10%
    Efficiency          (%) ==>                29.15

    Fuel Cost  (mills/kW.h) ==>                29.86
    Fuel Consumption (kt/a) ==>                 2.23
```

```
                         Project Evaluation Package             APR 10 1984

                 Costs for        BAMFIELD COAL

    Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
       Construction Cost                     4751       225       290      5266
       Contingency Allowance                  475        22        29       527
       Overhead Allowance                     470        22        29       521
       Interest During Const.                 228         0        15       242
       Total Capital Cost                    5924       270       362      6556
       Cost per KiloWatt ($/KW)              5924       270       362      6536

    Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
       Capital Recovery                       614        29        38       681
       Operation & Maintenance                 46         5         3        53
       School Taxes                            70         4         5        79
       Fuel Costs                             139         0         0       139
       Total Annual Cost                      868        38        46       952
       Cost per KW.h (mills/kW.h)          186.71      8.07      9.98    204.77
```

D.2.8. Bamfield Distribution

Project Evaluation Package APR 5 1984

Project Data For: BAMFIELD TRANS.

Project Capability

Peak Capacity	(MW)	1.80
Firm Energy	(GW.h)	4.65
Secondary Energy	(GW.h)	.00

Notes on Project Data

Project Evaluation Package APR 5 1984
Capital Cost Information for BAMFIELD TRANS.

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	0	.00	.00	0	0
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	2990	20.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	0	.00	.00	0	0

Project Evaluation Package APR 5 1984
Operating Cost Information for BAMFIELD TRANS.

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Variable Charges mills/kW.h
Generation				
Cost 1	.00	.00	.00	.00
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	41.66
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.00	.00	.00	.00

Project Evaluation Package APR 5 1984

Costs for BAMFIELD TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	2990	0	2990
Contingency Allowance	0	598	0	598
Overhead Allowance	0	323	0	323
Interest During Const.	0	0	0	0
Total Capital Cost	0	3911	0	3911
Cost per KiloWatt ($/KW)	0	2173	0	2173

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	226	0	226
Operation & Maintenance	0	262	0	262
School Taxes	0	61	0	61
Fuel Costs	0	0	0	0
Total Annual Cost	0	549	0	549
Cost per KW.h (mills/kW.h)	.00	118.08	.00	118.08

4%

Project Evaluation Package APR 5 1984

Costs for BAMFIELD TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	2990	0	2990
Contingency Allowance	0	598	0	598
Overhead Allowance	0	323	0	323
Interest During Const.	0	0	0	0
Total Capital Cost	0	3911	0	3911
Cost per KiloWatt ($/KW)	0	2173	0	2173

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	284	0	284
Operation & Maintenance	0	262	0	262
School Taxes	0	61	0	61
Fuel Costs	0	0	0	0
Total Annual Cost	0	607	0	607
Cost per KW.h (mills/kW.h)	.00	130.54	.00	130.54

6%

Project Evaluation Package APR 5 1984

Costs for BAMFIELD TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	2990	0	2990
Contingency Allowance	0	598	0	598
Overhead Allowance	0	323	0	323
Interest During Const.	0	0	0	0
Total Capital Cost	0	3911	0	3911
Cost per KiloWatt ($/KW)	0	2173	0	2173

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	347	0	347
Operation & Maintenance	0	262	0	262
School Taxes	0	61	0	61
Fuel Costs	0	0	0	0
Total Annual Cost	0	670	0	670
Cost per KW.h (mills/kW.h)	.00	144.15	.00	144.15

8%

Project Evaluation Package APR 5 1984

Costs for BAMFIELD TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	2990	0	2990
Contingency Allowance	0	598	0	598
Overhead Allowance	0	323	0	323
Interest During Const.	0	0	0	0
Total Capital Cost	0	3911	0	3911
Cost per KiloWatt ($/KW)	0	2173	0	2173

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	415	0	415
Operation & Maintenance	0	262	0	262
School Taxes	0	61	0	61
Fuel Costs	0	0	0	0
Total Annual Cost	0	738	0	738
Cost per KW.h (mills/kW.h)	.00	158.66	.00	158.66

10%

APPENDIX E

ENERGY COSTS - BELLA BELLA

E.1 INTRODUCTION

Appendix E is similar to Appendix D except that it summarizes the cost comparisons for Bella Bella. The alternatives were compared at 4, 6, 8 and 10 percent net discount rates. The energy costs are summarized in Table AE1-1. The gross unit energy costs at a 4 percent net discount rate, which is used in B.C. Hydro studies, range from 100 mills/kW·h for transmission from Ocean Falls to 225 mills/kW·h for wood gas-engine generation. Similarly, at a 10 percent net discount rate the gross unit energy costs range from 139 mills/kW·h for transmission from Ocean Falls to 309 mills/kW·h for wind generation. The relative changes in energy costs with discount rate reflects the variation in construction costs among alternatives. The gross unit energy costs of alternatives with higher construction costs escalate more rapdily at increasing discount rates. The equivalent incremental energy cost for No. 2 fuel oil which is used for comparison with fuel savers is 102 mills/kW·h (December 1983).

Section E.2 consists of computer printouts which list peak capacity, firm energy, secondary energy, construction costs, contingencies, overhead, project life, fixed operating and maintenance costs, taxes and variable charges such as the cost of electricity and water licence fees. For thermal alternatives, fuel costs are listed for various discount rates; the heating value, heat rate or effeciency, fuel cost and fuel consumption are also listed. For each discount rate the last table lists the computed costs in thousands of dollars as well as the capital cost per kilowatt and the gross unit energy cost in mills/kW·h.

TABLE AE1-1

UNIT ENERGY COST COMPARISONS AT VARIOUS NET INTEREST RATES - BELLA BELLA

	Diesel*1	Small Hydroelectric		Tidal	Wind	Thermal			Transmission
	Shearwater	Walker Lake	Lakes A, B, C & D	Hochstader Basin	Mount Hand	Wood Norman Morrison Bay	Wood-gas Norman Morrison Bay	Coal Norman Morrison Bay	Ocean Falls-Bella Bella
Peak Capacity (MW)	3.60	1.10	0.50	2.00	0.80	2.00	2.60	2.00	14.00
Annual Energy (GW·h)	10.35	7.70	3.50	7.00	2.26	10.35	10.35	10.35	10.35
Energy Cost (mills/kW·h) at 4% net	158	109	111	169	209	211	241	150	100
Energy Cost (mills/kW·h) at 6% net	161	133	136	206	240	232	258	166	112
Energy Cost (mills/kW·h) at 8% net	163	159	163	247	273	255	283	184	125
Energy Cost (mills/kW·h) at 10% net	166	187	192	290	309	280	306	203	139

---

*1 The equivalent energy cost of No. 2 fuel oil delivered to Bella Bella is estimated to be 102 mills/kW·h.

E.2 BELLA BELLA DIESEL[*1]

Project Capability

Peak capacity (MW)	3.60
Firm energy (GW·h)	10.35
Secondary energy (GW·h)	0.00

Costs for Bella Bella Diesel
(Discount Rate 4% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1859	-	-	1859
Cost per kilowatt ($/kW)	516	-	-	516

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	137	-	-	137
Operation and maintenance	407	-	-	407
School taxes	37	-	-	37
Fuel costs	1058	-	-	1058
Total annual cost	1639	-	-	1639
Cost per kW·h (mills/kW·h)	158.36	-	-	158.36

[*1] Contains some station costs not included in other alternatives, but these are assumed to be small relative to the overall costs.

Costs for Bella Bella Diesel
(Discount Rate 6% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1859	-	-	1859
Cost per kilowatt ($/kW)	516	-	-	516

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	162	-	-	162
Operation and maintenance	407	-	-	407
School taxes	37	-	-	37
Fuel costs	1058	-	-	1058
Total annual cost	1664	-	-	1664
Cost per kW·h (mills/kW·h)	160.77	-	-	160.77

Costs for Bella Bella Diesel
(Discount Rate 8% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1859	-	-	1859
Cost per kilowatt ($/kW)	516	-	-	516

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	189	-	-	189
Operation and maintenance	407	-	-	407
School taxes	37	-	-	37
Fuel costs	1058	-	-	1058
Total annual cost	1691	-	-	1691
Cost per kW·h (mills/kW·h)	163.38	-	-	163.38

Costs for Bella Bella Diesel
(Discount Rate 10% Net of Inflation)

Capital Cost Summary (k$)	Generation	Transmission	Substation	Total
Construction	-	-	-	-
Contingency allowance	-	-	-	-
Overhead allowance	-	-	-	-
Interest during construction	-	-	-	-
Total capital cost	1859	-	-	1859
Cost per kilowatt ($/kW)	516	-	-	516

Annual Cost Summary (k$)	Generation	Transmission	Substation	Total
Capital recovery	218	-	-	218
Operation and maintenance	407	-	-	407
School taxes	37	-	-	37
Fuel costs	1058	-	-	1058
Total annual cost	1720	-	-	1720
Cost per kW·h (mills/kW·h)	166.18	-	-	166.18

E.2.2. Bella Bella Small Hydroelectric

```
                    Project Evaluation Package              MAR 23 1984

Project Data For:        BELLA BELLA WALKER

Project Capability
   Peak Capacity      (MW)           1.10
   Firm Energy        (GW.h)         7.70
   Secondary Energy   (GW.h)          .00

Notes on Project Data
```

```
                    Project Evaluation Package              MAR 23 1984
              Capital Cost Information for BELLA BELLA WALKER

                   Construction  Contingency  Overhead   Cost   Project
                     Cost(K$)    Allowance(%)  Rate(%)   Distr.   Life
Generation
   Cost 1              5662        35.00         9.00      2       40
Transmission
   500 kV                 0          .00          .00      0        0
   360 kV                 0          .00          .00      0        0
   230 kV                 0          .00          .00      0        0
   132 kV                 0          .00          .00      0        0
    60 kV                 0          .00          .00      0        0
    25 kV              1889        20.00         9.00     22       30
Substation
   500 kV                 0          .00          .00      0        0
   360 kV                 0          .00          .00      0        0
   230 kV                 0          .00          .00      0        0
   132 kV                 0          .00          .00      0        0
    60 kV                 0          .00          .00      0        0
    25 kV               150        10.00         9.00     20       30
```

```
                    Project Evaluation Package              MAR 23 1984
             Operating Cost Information for BELLA BELLA WALKER

                    Fixed O & M    Taxes    Fixed Charge Variable Charges
                     % of CC      % of CC      $ / MW       mills/kW.h
Generation
   Cost 1              .48         1.33         .00           4.10
Transmission
   500 kV              .00          .00         .00            .00
   360 kV              .00          .00         .00            .00
   230 kV              .00          .00         .00            .00
   132 kV              .00          .00         .00            .00
    60 kV              .00          .00         .00            .00
    25 kV             1.90         1.70         .00            .00
Substation
   500 kV              .00          .00         .00            .00
   360 kV              .00          .00         .00            .00
   230 kV              .00          .00         .00            .00
   132 kV              .00          .00         .00            .00
    60 kV              .00          .00         .00            .00
    25 kV              .80         1.70         .00            .00
```

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WALKER

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	5662	1889	150	7701
Contingency Allowance	1982	378	15	2374
Overhead Allowance	688	204	15	907
Interest During Const.	186	0	3	189
Total Capital Cost	8517	2471	183	11171
Cost per KiloWatt ($/KW)	7743	2246	166	10156

4%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	430	143	11	584
Operation & Maintenance	68	43	1	113
School Taxes	102	39	3	143
Fuel Costs	0	0	0	0
Total Annual Cost	600	224	15	839
Cost per KW.h (mills/KW.h)	77.95	29.15	1.91	109.02

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WALKER

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	5662	1889	150	7701
Contingency Allowance	1982	378	15	2374
Overhead Allowance	688	204	15	907
Interest During Const.	279	0	5	284
Total Capital Cost	8611	2471	184	11266
Cost per KiloWatt ($/KW)	7828	2246	168	10242

6%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	572	180	13	765
Operation & Maintenance	68	43	1	113
School Taxes	102	39	3	143
Fuel Costs	0	0	0	0
Total Annual Cost	742	261	18	1021
Cost per KW.h (mills/KW.h)	96.39	33.91	2.28	132.58

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WALKER

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	5662	1889	150	7701
Contingency Allowance	1982	378	15	2374
Overhead Allowance	688	204	15	907
Interest During Const.	373	0	6	379
Total Capital Cost	8705	2471	186	11362
Cost per KiloWatt ($/KW)	7914	2246	169	10329

8%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	730	219	17	966
Operation & Maintenance	68	43	1	113
School Taxes	102	39	3	143
Fuel Costs	0	0	0	0
Total Annual Cost	900	301	21	1222
Cost per KW.h (mills/KW.h)	116.87	39.10	2.68	158.65

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WALKER

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	5662	1889	150	7701
Contingency Allowance	1982	378	15	2374
Overhead Allowance	688	204	15	907
Interest During Const.	468	0	8	475
Total Capital Cost	8799	2471	187	11457
Cost per KiloWatt ($/KW)	7999	2246	170	10416

10%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	900	252	20	1182
Operation & Maintenance	68	43	1	113
School Taxes	102	39	3	143
Fuel Costs	0	0	0	0
Total Annual Cost	1070	344	24	1437
Cost per KW.h (mills/KW.h)	138.92	44.64	3.12	186.68

```
                    Project Evaluation Package              APR 18 1984

Project Data For:      BELLA BELLA LAKE A-D

Project Capability
   Peak Capacity     (MW)             .50
   Firm Energy      (GW.h)           3.50
   Secondary Energy (GW.h)            .00

Notes on Project Data
```

```
                    Project Evaluation Package              APR 18 1984
               Capital Cost Information for BELLA BELLA LAKE A-D

                  Construction  Contingency  Overhead   Cost   Project
                  Cost(K$)      Allowance(%) Rate(%)    Distr.  Life
Generation
   Cost 1             3000        35.00        9.00       1      40
Transmission
   500 kV                0          .00         .00       0       0
   360 kV                0          .00         .00       0       0
   230 kV                0          .00         .00       0       0
   132 kV                0          .00         .00       0       0
    60 kV                0          .00         .00       0       0
    25 kV              700        10.00        9.00      22      30
Substation
   500 kV                0          .00         .00       0       0
   360 kV                0          .00         .00       0       0
   230 kV                0          .00         .00       0       0
   132 kV                0          .00         .00       0       0
    60 kV                0          .00         .00       0       0
    25 kV                0          .00         .00       0       0
```

```
                    Project Evaluation Package              APR 18 1984
               Operating Cost Information for BELLA BELLA LAKE A-D

                      Fixed O & M    Taxes    Fixed Charge Variable Charges
                       % of CC      % of CC      $ / MW       mills/kW.h
Generation
   Cost 1                .48         1.33          .00           4.10
Transmission
   500 kV                .00          .00          .00            .00
   360 kV                .00          .00          .00            .00
   230 kV                .00          .00          .00            .00
   132 kV                .00          .00          .00            .00
    60 kV                .00          .00          .00            .00
    25 kV               1.90         1.70          .00            .00
Substation
   500 kV                .00          .00          .00            .00
   360 kV                .00          .00          .00            .00
   230 kV                .00          .00          .00            .00
   132 kV                .00          .00          .00            .00
    60 kV                .00          .00          .00            .00
    25 kV                .00          .00          .00            .00
```

```
                  Project Evaluation Package              APR 18 1984

Benefits and Costs for        BELLA BELLA LAKE A-D

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                     3000       700         0      3700
   Contingency Allowance                 1050        70         0      1120
   Overhead Allowance                     364        69         0       434
   Interest During Const.                  59         0         0        59
   Total Capital Cost                    4473       839         0      5313
   Cost per KiloWatt ($/KW)              8947      1679         0     10625

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                       226        49         0       275
   Operation & Maintenance                 34        15         0        48
   School Taxes                            54        13         0        67
   Fuel Costs                               0         0         0         0
   Total Annual Cost                      314        76         0       390
   Cost per KW.h (mills/kW.h)           89.62     21.79       .00    111.41
```

4%

```
                  Project Evaluation Package              APR 18 1984

Benefits and Costs for        BELLA BELLA LAKE A-D

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                     3000       700         0      3700
   Contingency Allowance                 1050        70         0      1120
   Overhead Allowance                     364        69         0       434
   Interest During Const.                  88         0         0        88
   Total Capital Cost                    4503       839         0      5342
   Cost per KiloWatt ($/KW)              9005      1679         0     10684

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                       299        61         0       360
   Operation & Maintenance                 34        15         0        48
   School Taxes                            54        13         0        67
   Fuel Costs                               0         0         0         0
   Total Annual Cost                      387        89         0       476
   Cost per KW.h (mills/kW.h)          110.55     25.34       .00    135.89
```

6%

```
                  Project Evaluation Package              APR 18 1984

Benefits and Costs for        BELLA BELLA LAKE A-D

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                     3000       700         0      3700
   Contingency Allowance                 1050        70         0      1120
   Overhead Allowance                     364        69         0       434
   Interest During Const.                 118         0         0       118
   Total Capital Cost                    4532       839         0      5371
   Cost per KiloWatt ($/KW)              9064      1679         0     10743

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                       380        75         0       455
   Operation & Maintenance                 34        15         0        48
   School Taxes                            54        13         0        67
   Fuel Costs                               0         0         0         0
   Total Annual Cost                      468       102         0       570
   Cost per KW.h (mills/kW.h)          133.63     29.22       .00    162.85
```

8%

```
                  Project Evaluation Package              APR 18 1984

Benefits and Costs for        BELLA BELLA LAKE A-D

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                     3000       700         0      3700
   Contingency Allowance                 1050        70         0      1120
   Overhead Allowance                     364        69         0       434
   Interest During Const.                 147         0         0       147
   Total Capital Cost                    4562       839         0      5401
   Cost per KiloWatt ($/KW)              9123      1679         0     10802

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                       466        89         0       555
   Operation & Maintenance                 34        15         0        48
   School Taxes                            54        13         0        67
   Fuel Costs                               0         0         0         0
   Total Annual Cost                      554       117         0       671
   Cost per KW.h (mills/kW.h)          158.32     33.36       .00    191.68
```

10%

E.2.3. Bella Bella Tidal

```
                    Project Evaluation Package              MAR 23 1984

Project Data For:      HOCHSTADER BASIN

Project Capability
   Peak Capacity     (MW)            2.00
   Firm Energy      (GW.h)            .00
   Secondary Energy (GW.h)           7.00

Notes on Project Data
   2 MW TIDAL PLANT.  10 KM OF 25 KV TRANSMISSCN.
```

```
                    Project Evaluation Package              MAR 23 1984
               Capital Cost Information for HOCHSTADER BASIN

                  Construction  Contingency  Overhead  Cost   Project
                  Cost(K$)      Allowance(%) Rate(%)   Distr.  Life
Generation
   Cost 1            11470       20.00        9.00      18      40
Transmission
   500 kV                0         .00         .00       0       0
   360 kV                0         .00         .00       0       0
   230 kV                0         .00         .00       0       0
   132 kV                0         .00         .00       0       0
    60 kV                0         .00         .00       0       0
    25 kV              560       20.00        9.00      22      30
Substation
   500 kV                0         .00         .00       0       0
   360 kV                0         .00         .00       0       0
   230 kV                0         .00         .00       0       0
   132 kV                0         .00         .00       0       0
    60 kV                0         .00         .00       0       0
    25 kV                0         .00         .00       0       0
```

```
                    Project Evaluation Package              MAR 23 1984
              Operating Cost Information for HOCHSTADER BASIN

                     Fixed O & M    Taxes    Fixed Charge Variable Charges
                      % of CC      % of CC     $ / MW       mills/kW.h
Generation
   Cost 1              1.20         1.33        .00            .00
Transmission
   500 kV               .00          .00        .00            .00
   360 kV               .00          .00        .00            .00
   230 kV               .00          .00        .00            .00
   132 kV               .00          .00        .00            .00
    60 kV               .00          .00        .00            .00
    25 kV              1.90         1.70        .00            .00
Substation
   500 kV               .00          .00        .00            .00
   360 kV               .00          .00        .00            .00
   230 kV               .00          .00        .00            .00
   132 kV               .00          .00        .00            .00
    60 kV               .00          .00        .00            .00
    25 kV               .00          .00        .00            .00
```

Project Evaluation Package MAR 23 1984

Costs for HOCHSTADER BASIN

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	11470	560	0	12030
Contingency Allowance	2294	112	0	2406
Overhead Allowance	1239	60	0	1299
Interest During Const.	180	0	0	180
Total Capital Cost	15183	732	0	15915
Cost per KiloWatt ($/KW)	7591	366	0	7958
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	767	42	0	809
Operation & Maintenance	165	13	0	178
School Taxes	183	11	0	194
Fuel Costs	0	0	0	0
Total Annual Cost	1115	67	0	1182
Cost per KW.h (mills/KW.h)	159.33	9.51	.00	168.84

4%

Project Evaluation Package MAR 23 1984

Costs for HOCHSTADER BASIN

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	11470	560	0	12030
Contingency Allowance	2294	112	0	2406
Overhead Allowance	1239	60	0	1299
Interest During Const.	270	0	0	270
Total Capital Cost	15273	732	0	16005
Cost per KiloWatt ($/KW)	7636	366	0	8003
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	1015	53	0	1068
Operation & Maintenance	165	13	0	178
School Taxes	183	11	0	194
Fuel Costs	0	0	0	0
Total Annual Cost	1363	77	0	1441
Cost per KW.h (mills/kW.h)	194.75	11.06	.00	205.81

6%

Project Evaluation Package MAR 23 1984

Costs for HOCHSTADER BASIN

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	11470	560	0	12030
Contingency Allowance	2294	112	0	2406
Overhead Allowance	1239	60	0	1299
Interest During Const.	360	0	0	360
Total Capital Cost	15363	732	0	16095
Cost per KiloWatt ($/KW)	7681	366	0	8048
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	1288	65	0	1353
Operation & Maintenance	165	13	0	178
School Taxes	183	11	0	194
Fuel Costs	0	0	0	0
Total Annual Cost	1637	89	0	1726
Cost per KW.h (mills/kW.h)	233.79	12.75	.00	246.54

8%

Project Evaluation Package MAR 23 1984

Costs for HOCHSTADER BASIN

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	11470	560	0	12030
Contingency Allowance	2294	112	0	2406
Overhead Allowance	1239	60	0	1299
Interest During Const.	450	0	0	450
Total Capital Cost	15453	732	0	16185
Cost per KiloWatt ($/KW)	7726	366	0	8093
Annual Cost Summary (K$)	**Gener.**	**Trans.**	**Subst.**	**Total**
Capital Recovery	1580	78	0	1658
Operation & Maintenance	165	13	0	178
School Taxes	183	11	0	194
Fuel Costs	0	0	0	0
Total Annual Cost	1928	102	0	2030
Cost per KW.h (mills/kW.h)	275.49	14.56	.00	290.05

10%

E.2.4. Bella Bella Wind

Project Evaluation Package MAR 23 1984

Project Data For: BELLA BELLA WIND 200

Project Capability		
Peak Capacity	(MW)	.80
Firm Energy	(GW.h)	.00
Secondary Energy	(GW.h)	2.26

Notes on Project Data

Project Evaluation Package MAR 23 1984
Capital Cost Information for BELLA BELLA WIND 200

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	4200	10.00	9.00	22	20
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	80	10.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	0	.00	.00	0	0

Project Evaluation Package MAR 23 1984
Operating Cost Information for BELLA BELLA WIND 200

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Variable Charges mills/kW.h
Generation				
Cost 1	2.00	.00	.00	.00
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.00	.00	.00	.00

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WIND 200

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	4200	80	0	4280
Contingency Allowance	420	8	0	428
Overhead Allowance	416	8	0	424
Interest During Const.	0	0	0	0
Total Capital Cost	5036	96	0	5132
Cost per KiloWatt ($/KW)	6295	120	0	6415

4%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	371	6	0	376
Operation & Maintenance	92	2	0	94
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	463	9	0	472
Cost per KW.h (mills/kW.h)	204.84	3.86	.00	208.70

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WIND 200

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	4200	80	0	4280
Contingency Allowance	420	8	0	428
Overhead Allowance	416	8	0	424
Interest During Const.	0	0	0	0
Total Capital Cost	5036	96	0	5132
Cost per KiloWatt ($/KW)	6295	120	0	6415

6%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery.	439	7	0	446
Operation & Maintenance	92	2	0	94
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	531	10	0	542
Cost per KW.h (mills/kW.h)	235.15	4.49	.00	239.64

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WIND 200

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	4200	80	0	4280
Contingency Allowance	420	8	0	428
Overhead Allowance	416	8	0	424
Interest During Const.	0	0	0	0
Total Capital Cost	5036	96	0	5132
Cost per KiloWatt ($/KW)	6295	120	0	6415

8%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	513	9	0	521
Operation & Maintenance	92	2	0	94
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	605	12	0	617
Cost per KW.h (mills/kW.h)	267.84	5.17	.00	273.01

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA WIND 200

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	4200	80	0	4280
Contingency Allowance	420	8	0	428
Overhead Allowance	416	8	0	424
Interest During Const.	0	0	0	0
Total Capital Cost	5036	96	0	5132
Cost per KiloWatt ($/KW)	6295	120	0	6415

10%

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	592	10	0	602
Operation & Maintenance	92	2	0	94
School Taxes	0	1	0	1
Fuel Costs	0	0	0	0
Total Annual Cost	684	13	0	697
Cost per KW.h (mills/kW.h)	302.61	5.90	.00	308.52

E.2.5. Bella Bella Wood Thermal

Project Evaluation Package MAR 28 1984

Project Data For: BELLA BELLA WOOD TH.

Project Capability		
Peak Capacity	(MW)	2.00
Firm Energy	(GW.h)	10.35
Secondary Energy	(GW.h)	.00

Notes on Project Data

Project Evaluation Package MAR 28 1984

Capital Cost Information for BELLA BELLA WOOD TH.

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	8627	10.00	9.00	8	35
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	225	10.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	462	10.00	9.00	20	30

Project Evaluation Package MAR 28 1984

Operating Cost Information for BELLA BELLA WOOD TH.

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Varicble Charges mills/kW.h
Generation				
Cost 1	.88	1.33	.00	.14
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.80	1.70	.00	.00

```
                    Project Evaluation Package               MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD TH.

Unit Fuel Cost    ($/GJ) ==>            .00
             ($/tonne) ==>            80.55
Calorific Value (MJ/Kg) ==>            16.74

Heat Rate       (GJ/GWh) ==>        16440.00     4%
Efficiency          (%) ==>            .00

Fuel Cost  (mills/kW.h) ==>           79.11
Fuel Consumption (kt/a) ==>           10.16
```

```
                    Project Evaluation Package               MAR 28 1984

          Costs for          BELLA BELLA WOOD TH.

Capital Cost Summary (K$)              Gener.    Trans.    Subst.    Total
   Construction Cost                    8627       225       462      9314
   Contingency Allowance                 863        22        46       931
   Overhead Allowance                    854        22        46       922
   Interest During Const.                306         0         9       315
   Total Capital Cost                  10650       270       563     11483
   Cost per KiloWatt ($/KW)             5325       135       282      5741

Annual Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Capital Recovery                      571        16        33       619
   Operation & Maintenance                85         5         4        94
   School Taxes                          126         4         9       139
   Fuel Costs                            819         0         0       819
   Total Annual Cost                    1601        25        45      1670
   Cost per KW.h (mills/kW.h)         154.64      2.37      4.37    161.38
```

```
                    Project Evaluation Package               MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD TH.

Unit Fuel Cost    ($/GJ) ==>            .00
             ($/tonne) ==>            83.30
Calorific Value (MJ/Kg) ==>            16.74

Heat Rate       (GJ/GWh) ==>        16440.00     6%
Efficiency          (%) ==>            .00

Fuel Cost  (mills/kW.h) ==>           81.81
Fuel Consumption (kt/a) ==>           10.16
```

```
                    Project Evaluation Package               MAR 28 1984

          Costs for          BELLA BELLA WOOD TH.

Capital Cost Summary (K$)              Gener.    Trans.    Subst.    Total
   Construction Cost                    8627       225       462      9314
   Contingency Allowance                 863        22        46       931
   Overhead Allowance                    854        22        46       922
   Interest During Const.                459         0        14       473
   Total Capital Cost                  10803       270       568     11641
   Cost per KiloWatt ($/KW)             5402       135       284      5820

Annual Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Capital Recovery                      745        20        41       806
   Operation & Maintenance                85         5         4        94
   School Taxes                          126         4         9       139
   Fuel Costs                            847         0         0       847
   Total Annual Cost                    1803        29        54      1885
   Cost per KW.h (mills/kW.h)         174.20      2.75      5.21    182.17
```

```
                    Project Evaluation Package                 MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD TH.

Unit Fuel Cost   ($/GJ) ==>              .00
               ($/tonne) ==>            86.15
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate       (GJ/GWh) ==>         16440.00
Efficiency           (%) ==>              .00

Fuel Cost  (mills/kW.h) ==>             84.61
Fuel Consumption (kt/a) ==>             10.16
```

8%

```
                    Project Evaluation Package                 MAR 28 1984

          Costs for       BELLA BELLA WOOD TH.

                                     Gener.    Trans.    Subst.    Total
Capital Cost Summary (K$)
   Construction Cost                  8627       225       462      9314
   Contingency Allowance               863        22        46       931
   Overhead Allowance                  854        22        46       922
   Interest During Const.              612         0        19       631
   Total Capital Cost                10956       270       573     11798
   Cost per KiloWatt ($/KW)           5478       135       286      5899

                                     Gener.    Trans.    Subst.    Total
Annual Cost Summary (K$)
   Capital Recovery                    940        24        51      1015
   Operation & Maintenance              85         5         4        94
   School Taxes                        126         4         9       139
   Fuel Costs                          876         0         0       876
   Total Annual Cost                  2027        33        64      2123
   Cost per KW.h (mills/kW.h)       195.84      3.18      6.14    205.15
```

```
                    Project Evaluation Package                 MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD TH.

Unit Fuel Cost   ($/GJ) ==>              .00
               ($/tonne) ==>            89.15
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate       (GJ/GWh) ==>         16440.00
Efficiency           (%) ==>              .00

Fuel Cost  (mills/kW.h) ==>             87.55
Fuel Consumption (kt/a) ==>             10.16
```

10%

```
                    Project Evaluation Package                 MAR 28 1984

          Costs for       BELLA BELLA WOOD TH.

                                     Gener.    Trans.    Subst.    Total
Capital Cost Summary (K$)
   Construction Cost                  8627       225       462      9314
   Contingency Allowance               863        22        46       931
   Overhead Allowance                  854        22        46       922
   Interest During Const.              765         0        23       789
   Total Capital Cost                11109       270       577     11956
   Cost per KiloWatt ($/KW)           5555       135       289      5978

                                     Gener.    Trans.    Subst.    Total
Annual Cost Summary (K$)
   Capital Recovery                   1152        29        61      1242
   Operation & Maintenance              85         5         4        94
   School Taxes                        126         4         9       139
   Fuel Costs                          906         0         0       906
   Total Annual Cost                  2269        38        74      2381
   Cost per KW.h (mills/kW.h)       219.25      3.63      7.14    230.02
```

E.2.6. Bella Bella Wood Gasification

```
                         Project Evaluation Package              MAR 28 1984

Project Data For:        BELLA BELLA WOOD GAS

Project Capability
   Peak Capacity      (MW)          2.62
   Firm Energy       (GW.h)        10.35
   Secondary Energy  (GW.h)          .00

Notes on Project Data
```

```
                         Project Evaluation Package              MAR 28 1984
                   Capital Cost Information for BELLA BELLA WOOD GAS

                   Construction  Contingency  Overhead   Cost   Project
                   Cost(K$)      Allowance(%) Rate(%)    Distr. Life
Generation
   Cost 1              9215        10.00        9.00      10      20
Transmission
   500 kV                 0          .00         .00       0       0
   360 kV                 0          .00         .00       0       0
   230 kV                 0          .00         .00       0       0
   132 kV                 0          .00         .00       0       0
    60 kV                 0          .00         .00       0       0
    25 kV               225        10.00        9.00      22      30
Substation
   500 kV                 0          .00         .00       0       0
   360 kV                 0          .00         .00       0       0
   230 kV                 0          .00         .00       0       0
   132 kV                 0          .00         .00       0       0
    60 kV                 0          .00         .00       0       0
    25 kV               462        10.00        9.00      20      30
```

```
                         Project Evaluation Package              MAR 28 1984
                  Operating Cost Information for BELLA BELLA WOOD GAS

                   Fixed O & M     Taxes    Fixed Charge Varicble Charges
                    % of CC       % of CC      $ / MW      mills/kW.h
Generation
   Cost 1            3.60           .98          .00           .70
Transmission
   500 kV             .00           .00          .00           .00
   360 kV             .00           .00          .00           .00
   230 kV             .00           .00          .00           .00
   132 kV             .00           .00          .00           .00
    60 kV             .00           .00          .00           .00
    25 kV            1.90          1.70          .00           .00
Substation
   500 kV             .00           .00          .00           .00
   360 kV             .00           .00          .00           .00
   230 kV             .00           .00          .00           .00
   132 kV             .00           .00          .00           .00
    60 kV             .00           .00          .00           .00
    25 kV             .80          1.70          .00           .00
```

```
                    Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD GAS

Unit Fuel Cost   ($/GJ) ==>              .00
             ($/tonne) ==>            80.55
Calorific Value (MJ/Kg) ==>            16.74

Heat Rate      (GJ/GWh) ==>         19250.00      4%
Efficiency          (%) ==>              .00

Fuel Cost  (mills/kW.h) ==>            92.63
Fuel Consumption (kt/a) ==>            11.90
```

```
                    Project Evaluation Package              MAR 28 1984

          Costs for        BELLA BELLA WOOD GAS

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                     9215       225       462      9902
   Contingency Allowance                  921        22        46       990
   Overhead Allowance                     912        22        46       980
   Interest During Const.                 230         0         9       239
   Total Capital Cost                   11279       270       563     12112
   Cost per KiloWatt ($/KW)              4305       103       215      4623

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                       830        16        33       878
   Operation & Maintenance                372         5         4       381
   School Taxes                            99         4         9       112
   Fuel Costs                             959         0         0       959
   Total Annual Cost                     2260        25        45      2330
   Cost per KW.h (mills/kW.h)          218.37      2.37      4.37    225.11
```

```
                    Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD GAS

Unit Fuel Cost   ($/GJ) ==>              .00
             ($/tonne) ==>            83.30
Calorific Value (MJ/Kg) ==>            16.74

Heat Rate      (GJ/GWh) ==>         19250.00      6 %
Efficiency          (%) ==>              .00

Fuel Cost  (mills/kW.h) ==>            95.79
Fuel Consumption (kt/a) ==>            11.90
```

```
                    Project Evaluation Package              MAR 28 1984

          Costs for        BELLA BELLA WOOD GAS

Capital Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Construction Cost                     9215       225       462      9902
   Contingency Allowance                  921        22        46       990
   Overhead Allowance                     912        22        46       980
   Interest During Const.                 345         0        14       359
   Total Capital Cost                   11394       270       568     12231
   Cost per KiloWatt ($/KW)              4349       103       217      4668

Annual Cost Summary (K$)                Gener.    Trans.    Subst.    Total
   Capital Recovery                       993        20        41      1054
   Operation & Maintenance                372         5         4       381
   School Taxes                            99         4         9       112
   Fuel Costs                             991         0         0       991
   Total Annual Cost                     2456        29        54      2539
   Cost per KW.h (mills/kW.h)          237.32      2.75      5.21    245.29
```

```
                     Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD GAS

Unit Fuel Cost   ($/GJ) ==>               .00
             ($/tonne) ==>              86.15
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate      (GJ/GWh) ==>          19250.00        8 %
Efficiency          (%) ==>               .00

Fuel Cost  (mills/kW.h) ==>             99.07
Fuel Consumption (kt/a) ==>             11.90
```

```
                     Project Evaluation Package              MAR 28 1984

               Costs for        BELLA BELLA WOOD GAS

Capital Cost Summary (K$)              Gener.    Trans.    Subst.    Total
   Construction Cost                     9215       225       462     9902
   Contingency Allowance                  921        22        46      990
   Overhead Allowance                     912        22        46      980
   Interest During Const.                 460         0        19      478
   Total Capital Cost                   11508       270       573    12351
   Cost per KiloWatt ($/KW)              4393       103       219     4714

Annual Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Capital Recovery                      1172        24        51     1247
   Operation & Maintenance                372         5         4      381
   School Taxes                            99         4         9      112
   Fuel Costs                            1025         0         0     1025
   Total Annual Cost                     2669        33        64     2765
   Cost per KW.h (mills/kW.h)          257.87      3.18      6.14   267.19
```

```
                     Project Evaluation Package              MAR 28 1984

Fuel Cost Data for  BELLA BELLA WOOD GAS

Unit Fuel Cost   ($/GJ) ==>               .00
             ($/tonne) ==>              89.15
Calorific Value (MJ/Kg) ==>             16.74

Heat Rate      (GJ/GWh) ==>          19250.00        10 %
Efficiency          (%) ==>               .00

Fuel Cost  (mills/kW.h) ==>            102.52
Fuel Consumption (kt/a) ==>             11.90
```

```
                     Project Evaluation Package              MAR 28 1984

               Costs for        BELLA BELLA WOOD GAS

Capital Cost Summary (K$)              Gener.    Trans.    Subst.    Total
   Construction Cost                     9215       225       462     9902
   Contingency Allowance                  921        22        46      990
   Overhead Allowance                     912        22        46      980
   Interest During Const.                 575         0        23      598
   Total Capital Cost                   11623       270       577    12470
   Cost per KiloWatt ($/KW)              4436       103       220     4760

Annual Cost Summary (K$)               Gener.    Trans.    Subst.    Total
   Capital Recovery                      1365        29        61     1455
   Operation & Maintenance                372         5         4      381
   School Taxes                            99         4         9      112
   Fuel Costs                            1061         0         0     1061
   Total Annual Cost                     2898        38        74     3009
   Cost per KW.h (mills/kW.h)          279.98      3.63      7.14   290.75
```

E.2.7 Bella Bella Coal Thermal

Project Evaluation Package APR 10 1984

Project Data For: BELLA BELLA COAL

Project Capability		
Peak Capacity	(MW)	2.00
Firm Energy	(GW.h)	10.35
Secondary Energy	(GW.h)	.00

Notes on Project Data

Project Evaluation Package APR 10 1984

Capital Cost Information for BELLA BELLA COAL

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation Cost 1	7866	10.00	9.00	6	35
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	225	10.00	9.00	22	30
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	0	.00	.00	0	0
25 kV	462	10.00	9.00	20	30

Project Evaluation Package APR 10 1984

Operating Cost Information for BELLA BELLA COAL

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Variable Charges mills/kW.h
Generation Cost 1	.86	1.35	.00	.14
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	1.90	1.70	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.00	.00	.00	.00
25 kV	.80	1.70	.00	.00

```
                    Project Evaluation Package           APR 10 1984

Fuel Cost Data for  BELLA BELLA COAL

 Unit Fuel Cost   ($/GJ) ==>            .00
                ($/tonne) ==>         61.45
 Calorific Value (MJ/Kg) ==>          25.75

 Heat Rate       (GJ/GWh) ==>           .00        4%
 Efficiency           (%) ==>         29.13

 Fuel Cost  (mills/kW.h) ==>          29.49
 Fuel Consumption (kt/a) ==>           4.97
```

```
                    Project Evaluation Package           APR 10 1984

              Costs for        BELLA BELLA COAL

 Capital Cost Summary (K$)             Gener.   Trans.   Subst.   Total
    Construction Cost                   7866      225      462     8553
    Contingency Allowance                787       22       46      855
    Overhead Allowance                   779       22       46      847
    Interest During Const.               151        0        9      160
    Total Capital Cost                  9582      270      563    10415
    Cost per KiloWatt ($/KW)            4791      135      282     5208

 Annual Cost Summary (K$)              Gener.   Trans.   Subst.   Total
    Capital Recovery                     513       16       33      562
    Operation & Maintenance               76        5        4       85
    School Taxes                         117        4        9      130
    Fuel Costs                           305        0        0      305
    Total Annual Cost                   1011       25       45     1081
    Cost per KW.h (mills/kW.h)         97.71     2.37     4.37   104.45
```

```
                    Project Evaluation Package           APR 10 1984

Fuel Cost Data for  BELLA BELLA COAL

 Unit Fuel Cost   ($/GJ) ==>            .00
                ($/tonne) ==>         61.80
 Calorific Value (MJ/Kg) ==>          25.75

 Heat Rate       (GJ/GWh) ==>           .00        6%
 Efficiency           (%) ==>         29.13

 Fuel Cost  (mills/kW.h) ==>          29.66
 Fuel Consumption (kt/a) ==>           4.97
```

```
                    Project Evaluation Package           APR 10 1984

              Costs for        BELLA BELLA COAL

 Capital Cost Summary (K$)             Gener.   Trans.   Subst.   Total
    Construction Cost                   7866      225      462     8553
    Contingency Allowance                787       22       46      855
    Overhead Allowance                   779       22       46      847
    Interest During Const.               226        0       14      240
    Total Capital Cost                  9658      270      568    10495
    Cost per KiloWatt ($/KW)            4829      135      284     5248

 Annual Cost Summary (K$)              Gener.   Trans.   Subst.   Total
    Capital Recovery                     666       20       41      727
    Operation & Maintenance               76        5        4       85
    School Taxes                         117        4        9      130
    Fuel Costs                           307        0        0      307
    Total Annual Cost                   1166       29       54     1248
    Cost per KW.h (mills/kW.h)        112.64     2.75     5.21   120.60
```

```
                 Project Evaluation Package              APR 10 1984

Fuel Cost Data for  BELLA BELLA COAL

Unit Fuel Cost    ($/GJ) ==>               .00
               ($/tonne) ==>             62.15
Calorific Value (MJ/Kg) ==>              25.75

Heat Rate        (GJ/GWh) ==>              .00
Efficiency            (%) ==>            29.13

Fuel Cost  (mills/kW.h) ==>              29.83
Fuel Consumption (kt/a) ==>               4.97
```

8 %

```
                 Project Evaluation Package              APR 10 1984

          Costs for        BELLA BELLA COAL

Capital Cost Summary (K$)             Gener.    Trans.    Subst.    Total
   Construction Cost                   7866       225       462      8553
   Contingency Allowance                787        22        46       855
   Overhead Allowance                   779        22        46       847
   Interest During Const.               302         0        19       320
   Total Capital Cost                  9733       270       573     10575
   Cost per KiloWatt ($/KW)            4867       135       286      5288

Annual Cost Summary (K$)              Gener.    Trans.    Subst.    Total
   Capital Recovery                     835        24        51       910
   Operation & Maintenance               76         5         4        85
   School Taxes                         117         4         9       130
   Fuel Costs                           309         0         0       309
   Total Annual Cost                   1337        33        64      1433
   Cost per KW.h (mills/KW.h)        129.13      3.18      6.14    138.45
```

```
                 Project Evaluation Package              APR 10 1984

Fuel Cost Data for  BELLA BELLA COAL

Unit Fuel Cost    ($/GJ) ==>               .00
               ($/tonne) ==>             62.50
Calorific Value (MJ/Kg) ==>              25.75

Heat Rate        (GJ/GWh) ==>              .00
Efficiency            (%) ==>            29.13

Fuel Cost  (mills/kW.h) ==>              30.00
Fuel Consumption (kt/a) ==>               4.97
```

10 %

```
                 Project Evaluation Package              APR 10 1984

          Costs for        BELLA BELLA COAL

Capital Cost Summary (K$)             Gener.    Trans.    Subst.    Total
   Construction Cost                   7866       225       462      8533
   Contingency Allowance                787        22        46       855
   Overhead Allowance                   779        22        46       847
   Interest During Const.               377         0        23       401
   Total Capital Cost                  9809       270       577     10656
   Cost per KiloWatt ($/KW)            4904       135       289      5328

Annual Cost Summary (K$)              Gener.    Trans.    Subst.    Total
   Capital Recovery                    1017        29        61      1107
   Operation & Maintenance               76         5         4        85
   School Taxes                         117         4         9       130
   Fuel Costs                           310         0         0       310
   Total Annual Cost                   1520        38        74      1632
   Cost per KW.h (mills/kW.h)        146.88      3.63      7.14    157.65
```

E.2.8. Bella Bella Transmission

Project Evaluation Package MAR 27 1984

Project Data For: BELLA BELLA TRANS.

Project Capability		
Peak Capacity	(MW)	14.00
Firm Energy	(GW.h)	10.35
Secondary Energy	(GW.h)	.00

Notes on Project Data

Project Evaluation Package MAR 27 1984
Capital Cost Information for BELLA BELLA TRANS.

	Construction Cost(K$)	Contingency Allowance(%)	Overhead Rate(%)	Cost Distr.	Project Life
Generation					
Cost 1	0	.00	.00	0	0
Transmission					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	4889	20.00	9.00	21	30
25 kV	0	.00	.00	0	0
Substation					
500 kV	0	.00	.00	0	0
360 kV	0	.00	.00	0	0
230 kV	0	.00	.00	0	0
132 kV	0	.00	.00	0	0
60 kV	1390	10.00	9.00	20	30
25 kV	0	.00	.00	0	0

Project Evaluation Package MAR 23 1984
Operating Cost Information for BELLA BELLA TRANS.

	Fixed O & M % of CC	Taxes % of CC	Fixed Charge $ / MW	Variable Charges mills/kW.h
Generation				
Cost 1	.00	.00	.00	30.00
Transmission				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	1.90	1.70	.00	.00
25 kV	.00	.00	.00	.00
Substation				
500 kV	.00	.00	.00	.00
360 kV	.00	.00	.00	.00
230 kV	.00	.00	.00	.00
132 kV	.00	.00	.00	.00
60 kV	.80	1.70	.00	.00
25 kV	.00	.00	.00	.00

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	4889	1390	6279
Contingency Allowance	0	978	139	1117
Overhead Allowance	0	528	138	666
Interest During Const.	0	51	28	79
Total Capital Cost	0	6446	1695	8141
Cost per KiloWatt ($/KW)	0	460	121	581

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	373	98	471
Operation & Maintenance	311	111	12	434
School Taxes	0	100	26	126
Fuel Costs	0	0	0	0
Total Annual Cost	311	584	136	1031
Cost per KW.h (mills/kW.h)	30.00	56.42	13.16	99.58

4%

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Costs for BELLA BELLA TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	4889	1390	6279
Contingency Allowance	0	978	139	1117
Overhead Allowance	0	528	138	666
Interest During Const.	0	77	42	119
Total Capital Cost	0	6472	1709	8180
Cost per KiloWatt ($/KW)	0	462	122	584

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	470	124	594
Operation & Maintenance	311	111	12	434
School Taxes	0	100	26	126
Fuel Costs	0	0	0	0
Total Annual Cost	311	681	162	1154
Cost per KW.h (mills/kW.h)	30.00	65.83	15.69	111.52

6%

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	4889	1390	6279
Contingency Allowance	0	978	139	1117
Overhead Allowance	0	528	138	666
Interest During Const.	0	102	56	158
Total Capital Cost	0	6497	1723	8220
Cost per KiloWatt ($/KW)	0	464	123	587

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	577	153	730
Operation & Maintenance	311	111	12	434
School Taxes	0	100	26	126
Fuel Costs	0	0	0	0
Total Annual Cost	311	788	191	1290
Cost per KW.h (mills/kW.h)	30.00	76.17	18.48	124.64

8%

Project Evaluation Package MAR 23 1984

Costs for BELLA BELLA TRANS.

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	0	4889	1390	6279
Contingency Allowance	0	978	139	1117
Overhead Allowance	0	528	138	666
Interest During Const.	0	128	70	198
Total Capital Cost	0	6523	1737	8259
Cost per KiloWatt ($/KW)	0	466	124	590

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	0	692	184	876
Operation & Maintenance	311	111	12	434
School Taxes	0	100	26	126
Fuel Costs	0	0	0	0
Total Annual Cost	311	903	222	1436
Cost per KW.h (mills/kW.h)	30.00	87.26	21.49	138.75

10%

APPENDIX F

GLOSSARY AND ABBREVIATIONS

F.1 GLOSSARY

Actinolite	- A common silicate $(-S:O_4)$ mineral $[Ca_2(Fe,Mg)_5Si_8O_{22}(OH)_2]$.
Adit	- A "tunnel" which is driven into a hillside, but open at only one end.
Agmatite	- A rock of fragmental appearance which results from subjecting a pre-existing rock to very high temperature and pressure.
Almandine-amphibolite Facies	- A geologic environment where a group of minerals are formed which are characteristic of heating at a moderate temperature and pressure.
Amortize	- To repay a debt over time.
Amphibolite	- A rock which results from subjecting a pre-existing rock to high temperature and pressure.
Andesitic	- Consisting of andesite which is a type of volcanic rock.
Annual Energy	- The total energy output of the generating station over 1 year.
Argillite	- A well compacted, dense rock resulting from intense compaction of a mud.

Arsenopyrite - The most common arsenic mineral, used as a secondary source of arsenic (FeAsS).

Ash - Incombustible mineral matter which remains behind when coal burns completely.

Assemblage - A group of minerals which occur together and indicate some characteristics about the origin of the rock in which they occur.

Attitudes - Compass readings which are used to define the orientation of geologic structures in space.

Azurite - A blue copper mineral which commonly occurs as a result of the oxidation of other copper minerals $[Cu_3(CO_3)_2(OH)_2]$.

Baghouse Filters - A means of separating particulates (particles) from stack gases.

Barrage - A low dam or artificial barrier for impounding water.

Basalt - The most common type of volcanic rock.

Base Load - The minimum value of load over a given period of time. Thus base-loaded generators operate at essentially constant output.

Basin - Catchment area or watershed of a river.

Bitumen - Mixture of tarry hydrocarbons.

Black start capability	- The ability of a generating station to initiate a start-up when completely isolated from external electric power supplies.
Breccia	- A rock consisting of angular fragments.
Calc-alkalic	- A series of igneous rocks consisting of 56 to 61 percent silica (SiO_2) and which are characteristically associated with the formation of mountain-building.
Calcareous	- Containing calcium carbonate ($CaCO_3$).
Capacity	- Rated output of a machine apparatus or station measured in kilowatts, horsepower, etc.
Capacity Factor	- The ratio between the energy output over a specified period of time and the maximum energy which the generator could produce over that time.
Catalyst	- A substance which promotes a chemical reaction, but does not enter into the reaction itself.
Chalcopyrite	- The most common copper-bearing ore mineral in B.C. ($CuFeS_2$).
Chert	- A sedimentary rock which results from the deposition of silica (SiO_2).
Conglomerate	- A rock which results from the compaction or cementation of a gravel.
Critical Water Conditions	- A period of low streamflows which actually occurred in the past, which could re-occur in the future and which could cause hydroelectric reservoirs to be drawn down to minimum levels.

Cunit	- A measure of the quantity of solid wood (equal to 100 ft^3 or 2.83 m^3).
Cyclone Separators	- A means of separating particulates (particles) from stack gases.
Demand	- The amount of electricity required by the system or by the customer, averaged over a specified interval of time.
Diorite	- A common rock in the Coast Ranges of British Columbia which cooled from a molten state below the earth's surface.
Dip	- The angle a planar geologic feature is inclined from the horizontal; the dip is perpendicular to the strike.
Discordant Contact	- A sharp contact between two rock types which cuts across the layering.
Disseminated	- Widely dispersed and scattered throughout.
Distribution	- Low voltage electric transmission generally at voltages below 60 kV, and used for distributing electricity to customers.
Drift	- A "tunnel" which follows a vein or other feature.
Dry Land Sort	- Area for sorting logs by size, species and/or end use.
Dyke	- A non-horizontal tabular rock mass which moved into a crack while in motion.

Electric Energy - The use of electricity to perform work. Electricity used at a rate of 1 kilowatt for 1 hour uses 1 kilowatt-hour of electric energy.

Electric Power - The instantaneous rate at which electric energy is used, usually expressed in kilowatts (also used as a synonym for electricity).

Energy - The ability to do work, or the result of power applied for a period of time (measured in kilojoules, kilowatt-hours, etc.).

Energy Capability - The amount of energy a generating plant can produce in a given time (usually 1 year).

Epidote - A common silicate mineral $[Ca_2(Al,Fe)_3Si_3O_{12}(OH)]$.

Fault - A crack in the earth's crust where there is movement parallel to the crack.

Fibric Peat - Reddish-brown peat with more than two-thirds recognizable plant fiber.

Firm Energy - The assured supply of energy which allows for forced shutdown of the largest unit (at diesel stations) or for critical streamflows (at hydroelectric plants).

Fixed Carbon - Combustible residue left after the volatile matter is removed by distillation.

Flow - A structure resulting from the cooling of a "river" of lava.

Flume - An open, inclined trough which conducts water.

Foliation - The alignment of minerals commonly a result of subjecting a rock to high stress.

Freeboard - Height above high water.

Gabbro - A rock similar to a diorite.

Garnet - A relatively common group of silicate minerals [e.g. $Fe_3Al_2(SiO_4)_3$].

Gasification - The process of making a combustible gas from a solid or liquid.

Geologic Time Scale - See next "a-page".

Gneiss - A rock with moderately coarse crystals resulting from subjecting a previously existing rock to high temperature and pressure.

Gossan - An iron-rich residue from waters leaching a source of iron.

Granodiorite - A type of coarse rock resulting from molten rock cooling beneath the earth's surface.

Granulite Facies - A geologic environment where a group of minerals are formed which are characteristic of heating at very high temperature and pressure.

Geologic Time Scale

Era	Period	Epoch	Age*1
Cenozoic	Quaternary	Recent	0.01
		Pleistocene	1.5 to 2.0
	Tertiary	Pliocene	7
		Miocene	26
		Oligocene	37 to 38
		Eocene	53 to 54
		Paleocene	65
Mesozoic	Cretaceous		136
	Jurassic		195
	Triassic		225
Paleozoic	Permian		280
	Pennsylvanian		320
	Mississippian		345
	Devonian		395
	Silurian		430 to 440
	Ordivician		505
	Cambrian		570
Precambrian			

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*1 Millions of years to beginning of time interval.

Gravity-packed Unit	- A volumetric measure for hog fuel, consisting of 200 ft^3 (5.66 m^3) of loosely-packed material. 1 GPU is approximately equal to 1 short ton of oven-dry (OD) wood (0.91 ODtonnes).
Greenschist Facies	- A geologic environment where a group of minerals are formed which are characteristic of heating at a relatively low temperature and pressure.
Greenstone	- A general term for a green rock resulting from alteration of a previously existing rock, usually volcanic, at relatively low temperature and pressure.
Greywacke	- A type of sandstone which contains many fragments of previously existing rocks.
Head	- The difference between the water levels on the upstream and downstream sides of a dam or hydraulic turbine.
Headwaters	- The upper reaches or source of a river.
Hemic Peat	- Dark reddish brown peat with one-third to two-thirds recognizable plant fiber.
Hog Fuel	- Mechanically shredded wood waste.
Hornblende	- A common silicate ($-SiO_4$) mineral similar to actinolite $[NaCa_2(Mg,Fe,Al,)_5(Si,Al)_8O_{22}(OH)_2]$.
Hydraulic Turbine	- A machine which can transform the energy of falling or flowing water into mechanical energy.
Integrated System	- Interconnected by a network of transmission lines linking generating station(s) and customers.

Intrusion	- A body of rock which cooled from a molten state while below the earth's surface.
Island Arc	- An arcuate line of volcanic islands with active volcanoes and frequent earthquakes.
Liquefaction	- The process of making a combustible liquid from a gas or solid.
Load	- The amount of electricity required by a customer or group of customers.
Magnetite	- An ore of iron (Fe_3O_4).
Malachite	- A green copper mineral which commonly occurs as a result of the oxidation of other copper minerals $[Cu_2(CO_3)(OH)_2]$.
Mantle	- That part of the earth below the crust, from approximately 30 km deep to the outer core.
Marcasite	- A relatively common mineral which is similar to pyrite and is discarded as waste (FeS_2).
Massive	- Essentially devoid of any geologic textures or structures, homogeneous.
Mesic Peat	- Dark brown to black peat in the middle range on the Von Post scale; the structure is almost amorphous.
Metamorphism	- Changing the mineralogy and/or geologic structures and textures of a pre-existing rock by subjecting to increased temperature and/or pressure.

Metasedimentary	- A sedimentary rock which was subjected to high temperature and/or pressure.
Metavolcanic	- A volcanic rock which cooled and was subsequently subjected to high temperature and/or pressure.
Mineral-matter-free	- Without considering the weight of mineral matter in the raw coal.
Miocene	- Refer to the geologic time scale.
Mitigation	- Alteration of a project in such a way as to avoid or reduce negative impacts.
Norite	- A rock similar to a diorite.
Oceanic Plate	- The earth is divided by faults into a series of crustal plates; several of these plates comprise the ocean bottoms and are called oceanic plates.
Olivine	- A silicate mineral $[(Mg,Fe)SiO_4]$.
Peak	- Maximum instantaneous demand, usually averaged over a given period of time, such as 1 hour.
Pendant	- A body of the original rock surrounded by an intrusion.
Penstock	- Tube through which water flows from the reservoir to the turbines in a hydroelectric generating station.
Pillow Basalts	- Basalts consisting of ovoid structures resulting from cooling under water.

Plutonic - Molten rock that cooled at depth within the earth as opposed to volcanic which is molten rock that cooled at the surface of the earth.

Power - The instantaneous rate at which energy is used, measured in kilowatts.

Power Factor - A coefficient which gives a measure of the utilization of power which is being produced.

Present-worth-cost - The current value of a cost or expenditure in the future, based on compound interest at some specified rate over some given interval of time.

Pyrite - A common mineral which is discarded as waste (FeS_2).

Pyrolysis - Burning with little or no oxygen.

Pyrrhotite - Rarely used as an ore of iron and sulphur ($Fe_{1-x}S$).

Quartz - One of the most common minerals in the earth's crust (SiO_2).

Quartz Monzonite - Similar to diorite.

Quartzite - A rock containing abundant quartz (SiO_2) and resulting from subjecting a quartz-rich sandstone to low to high heat and/or pressure.

Retrograde - Subjecting a rock to a lower temperature and/or pressure.

Rhyolite - A common type of volcanic rock.

"Run-of-River" Plant	- A hydroelectric generating station operated with the unmodified flow of a river rather than from a storage reservoir; some "run-of-river" plants have small storage reservoirs.
Schist	- A rock similar to a gneiss, but consisting of abundant platy minerals.
Sedimentary	- Rocks which were originally deposited layer upon layer on the earth's surface at low temperature and pressure.
Shaft	- A "tunnel" opening extending downward from the surface at a steep angle.
Sheared	- Containing numerous parallel cracks or faults.
Showing	- A location where there is a mineral of economic interest.
Silica	- Silicon dioxide (SiO_2).
Sill	- A horizontal layer of rock which cooled from a molten state while below the earth's surface.
Siltstone	- A fine sedimentary rock consisting of particles between clay and sand sizes.
Skarn	- A rock consisting mainly of minerals with abundant calcium (Ca) and silicate (SiO_4) and which is commonly associated with limestone and an instrusion.
Sluicegate	- A gate which can be opened to reduce the water level in a reservoir.

Spillway	- A structure, including a chute usually controlled by gates or valves, to discharge excess water from a reservoir.
Splay	- A branch of a main fault.
Strike	- The direction of intersection of a planar geologic feature with a horizontal surface. Used with dip to uniquely define the orientation of a plane in space.
Subduction	- The movement of one crustal plate under another.
Sulphides	- Containing sulphur(s) along with a metal or metals.
Tetrahedrite	- A relatively common mineral in copper ores ($Cu_{12}Sb_4S_{13}$).
Tholeutic	- Basalts with little or no olivine and typically widespread over large areas of some continents.
Tidal Basin	- An inlet or bay which has a narrow or shallow entrance.
Tidal Range	- The change in sea level which occurs between consecutive low and high tides.
Tonalite	- A type of volcanic rock.
Transcurrent Fault	- A fault with horizontal movement which separates crustal plates.
Transformer	- An electrical device for changing alternating current electricity from one voltage to another.

Tuff	- A volcanic rock which was originally deposited as ash-like material.
Turbine	- A rotary device in an electric generating station which is turned by water, steam or combustion gases and which drives an electric generator.
U-shaped Valley	- The characteristic shape of a glaciated valley in a cross section.
Unconformably	- Having a long interval of erosion in prehistoric time which separates two rock units.
Utility-scale	- Projects of sufficient size to be economical for utility service.
Vein	- A crack filled with mineral matter deposited from underground waters.
Volatile Matter	- That portion of the coal which is driven off in gaseous form when the coal is subjected to a standardized temperature test.
Watershed	- The catchment basin of a river system.
Weir	- A low dam across a river which raises the water level slightly.
Xenolith	- An inclusion or rock fragment brocken from the surrounding rock and frozen in place within a molten rock as it cooled.

F.2 ABBREVIATIONS

A - Ampere

/a - Annually

°C - Degrees Celsius

CNG - Compressed natural gas

Enfor - Energy from the Forest, Environment Canada

°F - Degrees Farenheit

F.O.B. - Free on board

FD - Forced draft

FERIC - Forest Engineering Research Institute of Canada

GPU - Gravity packed unit

GW·h - Gigawatt-hour

h - Hour

ha - Hectare

HAHT - Horizontal axis hydraulic turbine

HAWT - Horizontal axis wind turbine

Hz - Hertz

ID - Induced draft

I.D.C. - Interest during construction

kg - Kilogram

km - Kilometre

km^2 - Square kilometre (100 ha)

kPa - Kilopascals

kV - Kilovolt

kW - Kilowatt

kW·h - Kilowatt-hour

lb - Pound

LNG - Liquefied natural gas

m - Metre

MSW - Municipal solid waste

MW - Megawatt

MW·h - Megawatt-hour

m^3 - Cubic metre

m^3/s - Cubic metre per second

NO_x - Oxides of nitrogen

OD - Oven-dried (approximately 10% moisture)

psig - Pounds per square inch gauge

rpm - Revolutions per minute

SO_2 - Sulphur dioxide

t - Tonnes

VAHT - Vertical axis hydraulic turbine

VAWT - Vertical axis wind turbine